APPENDIX
(Pages 921-1380)

Supreme Court of the United States

OCTOBER TERM, 1973

No. 72-402

UNITED STATES OF AMERICA,
Appellant

—v.—

GENERAL DYNAMICS CORPORATION, THE UNITED ELECTRIC COAL COMPANIES, and FREEMAN COAL MINING CORPORATION

ON APPEAL FROM THE UNITED STATES DISTRICT COURT FOR THE NORTHERN DISTRICT OF ILLINOIS

JURISDICTIONAL STATEMENT FILED SEPTEMBER 8, 1972
PROBABLE JURISDICTION NOTED DECEMBER 11, 1972

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INDEX

Government Exhibits:—Continued Page

Government Exhibits:—Continued

Government Exhibits:—Continued

Defense Exhibits:

Defense Exhibits:—Continued

Defense Exhibits:—Continued

Defense Exhibits:—Continued

Defense Exhibits:—Continued Page

Defense Exhibits:—Continued

Defense Exhibits:—Continued

Deposition Exhibits:—Continued Page

Deposition Exhibits:—Continued

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REPORT

OF THE

NATIONAL FUELS AND ENERGY STUDY GROUP

ON

AN ASSESSMENT OF AVAILABLE INFORMATION ON ENERGY IN THE UNITED STATES

TO THE

COMMITTEE ON INTERIOR AND INSULAR AFFAIRS UNITED STATES SENATE

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[illegible]

87th Congress }
2d Session } COMMITTEE PRINT

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SEPTEMBER 21, 1962

Printed for the use of the Committee on Interior and Insular Affairs

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CHAIRMAN ANDERSON'S MEMORANDUM OF TRANSMITTAL

SEPTEMBER 21, 1962.

To the Senate Committee on Interior and Insular Affairs:

I am transmitting herewith to the members of the Senate Committee on Interior and Insular Affairs and the ex officio members of the fuels policy study, as well as to other interested parties a staff report prepared for the committee as an assessment of available information on energy and fuels in the United States.

This study was initiated and conducted under authority of Senate Resolution 105 of the 87th Congress, 1st session. The study report was prepared by a special study group of experts recruited by the committee specifically for this task. The chairman of the study group is Mr. Samuel G. Lasky, an official in the Department of the Interior, and the members of the group are made up of professional men from private industry who were selected after conferences with and recommendations by spokesmen for our fuels industries.

I want to commend these gentlemen individually and as a group for their cooperation during the conduct of the study. As a result of their diligent efforts, in less than a year our committee has before it in a single volume pertinent information relating to fuels and energy essential to any further consideration we make of this important subject. I am particularly grateful to the chairman of the study group who was of great assistance to the committee in helping to meet promptly the deadline set for the study group's report.

In my view, our committee has been charged by the Senate with two main tasks under the authorizing resolution. The first was to gather the facts and figures pertaining to fuels and energy. This has been done in the present study. Our second and final task will be to study the information provided and, if it is the wish of the committee, to report our policy findings and recommendations to the Senate.

To help the committee with this task, we are distributing this study and inviting comments and suggestions which, when received, will be carefully considered in reaching any decisions respecting recommendations for congressional action. When the Interior and Insular Affairs Committee meets early in the 88th Congress, our assignment can be then completed.

I am convinced that the study group has made a real contribution to this Nation's store of knowledge on a complex and all-important subject, and that its report will prove of great value to the Government, to our fuels industries, and to the public.

CLINTON P. ANDERSON,
Chairman, Senate Committee on Interior and Insular Affairs.

REPORT

OF THE

NATIONAL FUELS AND ENERGY STUDY GROUP

ON

AN ASSESSMENT OF AVAILABLE INFORMATION ON ENERGY IN THE UNITED STATES

Samuel G. Lasky, Department of the Interior, *Chairman*
Herbert J. Bickel, Texas Eastern Transmission Corp.
Joseph J. Quinn, Rochester & Pittsburgh Coal Co.
John M. Ryan, Humble Oil & Refining Co.
Paul R. Schultz, Jr., *Consultant*

LETTER OF SUBMITTAL

U.S. Senate,
Committee on Interior and Insular Affairs,
September 7, 1962.

Hon. Clinton P. Anderson,
Chairman, Committee on Interior and Insular Affairs,
U.S. Senate, Washington, D.C.

Dear Mr. Chairman: We are honored to present herewith to the Senate Committee on Interior and Insular Affairs our assessment of the available information on energy in the United States. The report is the result of roughly 10 months of effort; although work was started as early as August 1961, the study group was not fully assembled until November. More information could be included, and the analysis made a little more penetrating, here and there, but the broad conclusions to be derived would remain unchanged and we do not think the additional time and effort would be justified.

The report presents first a brief historical and economic perspective, examines current opinion about future consumption of energy, considers one by one the various déterminates of supply (reserves, plant capacity, transportation, labor supply and productivity, technology, marketing, competition, and like influences), and then compares the estimated future consumption with the Nation's ability to supply it. The years 1965 and 1980 were selected as check points. Emergency as well as peacetime demand and supply are covered. A subsequent chapter discusses the economic and social costs of various policy directions, and the last chapter of all presents the opinions of industry and consumer groups as to what they think national fuels and energy policy should be, in their own words.

Your instructions regarding the making of this study are presented in the introduction to the report. In brief, the instructions were to assemble the information that is currently available, to study it, and to assess its worth. In doing so we found ourselves continuously dismayed to learn how little positive information exists, how much is impression and folklore, in subject area after subject area, in industry after industry. Belief in this folklore is deep and it is held with passionate, though honest, tenacity. Too often, to our minds, have we been forced to write: "No one knows * * *." One result of this set of circumstances is that our report contains occasional statements that do not have the complete endorsement of one or another of the members of the study group. All this we have tried to record faithfully and objectively. Yet despite the imperfect fabric of fact, we think there has emerged from this study a reasonably good picture of energy in the United States and of the policy, legal, and regulatory framework within which it sets. It is our earnest hope and belief that we have given you and your committee the information you want.

Through you we want to acknowledge the generous and expert cooperation provided us by many Government agencies, trade associations, companies, and individuals in providing us with information and in checking our draft report. The credit for whatever value this report may have must be shared with them.

Respectfully submitted.

NATIONAL FUELS AND ENERGY STUDY GROUP,
SAMUEL G. LASKY, *Chairman.*

CONTENTS

LIST OF ILLUSTRATIONS

REPORT OF THE NATIONAL FUELS AND ENERGY STUDY GROUP

SUMMARY

The basic purpose of this report is to compile and assess an existing body of information, and hence the report does not readily lend itself to being summarized in the usual sense. Nevertheless, we have tried here to condense the information and to indicate its drift in such a way as to give the reader a useful guide, so that he may be able to select such part of the contents as he wishes for detailed reading.

REQUIREMENTS

There is a reasonable consensus among the experts that the Nation's projected requirements will nearly double by 1980 (to about 82 quadrillion B.t.u.'s), that generation of electric energy will multiply by some 3½ times (to about 2,700 billion kilowatt-hours), and that consumption of oil will increase by about two-thirds (to, say, 5.7 billion barrels). The consensus for coal, gas, and nuclear energy is not so clear cut, but the following deductions have been accepted as usable for the policy-tailored framework of this report: coal consumption roughly to double by 1980 (to 800 million tons or more), gas almost to double (to 20 trillion cubic feet or more), hydropower generation to drop from a share equal to 4 percent of total energy consumption to about 2½ percent, and nuclear energy to increase to a level about equal to hydropower.

Quantitative estimates of emergency requirements—a euphemism for wartime requirements—are meaningful only in relation to a near-future contingency. For this and other reasons, we assume that the nonmilitary part of wartime requirements will be within the margin of error inherent in the peacetime figures projected for 1965: i.e., 11 million barrels of oil a day, 15 trillion cubic feet of gas a year, 500 million tons of coal a year, and 1,100 billion kilowatt-hours a year. For oil there would be an additional military demand approaching 3 million barrels a day.

These figures do not apply to nuclear war, of course. In the period immediately following an attack, the civilian population would have to get along with such quantities and kinds of fuels as are at hand locally. We presume that the military arm has petroleum fuels in hand to support the immediate retaliatory blow. The demand for petroleum products would increase as military action mounts, and the demand for all forms of energy would increase as national authority is restored and industrial activity is resumed. The top limit of this increase is conditioned by how long the war would last and the course it takes. All energy demands would remain high during the period of reconstruction.

SUPPLY

The Nation's resource base, in terms of each fuel, is adequate to meet projected requirements for the period covered by this study—i.e., to 1980. The 20 billion tons of coal even now commercially available (reserves) is more than enough comfortably to support a 1980 coal output of even as much as 800 million tons. There is plenty of oil in the ground but one or more steps may be needed to realize it: rate of exploration be stepped up, more attention be given to secondary recovery, ratio of reserves to rate of output be established at some figure well below the usual range of 12 to 14. The Nation has the ability to be self-sufficient in oil if it so wills. Imports could be called on if desired, there being no dearth of foreign oil, and so could the oil in oil shale. Oil shale may in fact actually be yielding oil well before 1980, and coal may be yielding gasoline. The domestic supply of gas available appears to be safely well above the projected requirement. High B.t.u. gas from coal is in the near offing. A comparison between projected consumption of electric energy (regardless of source) and the ability to supply it yields the prompt and simple answer that there should be no difficulties in that area. While nuclear power faces several problems, it is an accomplished technological fact.

Conventional fossil fuels plus shale oil and fissionable materials contain recoverable energy equivalent to 800 years of usage at the current rate. Improvement in nuclear technology could expand this figure eightfold. This outlook is without the benefit of foreign supplies, fissionable materials available at prices higher than those now paid, coal and shale oil beyond the limited quantities assumed to be recoverable, or the energy potential of unconventional sources.

There is also a large present plant capacity and apparently an industrial ability to generate the funds to expand the capacity as needed. Labor supply should pose no problems; the only sector about which doubt has been expressed is in regard to coal miners; and here it appears that, because of expected continued improvement in output per man-day, the 800 million tons of 1980 conceivably could be produced by a labor force even smaller than the force presently at work.

Transportation has sometimes been considered a bottleneck in the energy complex. The concern appears exaggerated. Transportation of oil and gas is a matter of investment. An aggressive research on extra-high voltage transmission almost assures continued economic transportation of electric power. The only real question relates to a shortage of railroad cars for the movement of coal. Such shortages as occur are not the result of a shortage of cars as such but of cars that are serviceable. The railroads repair damaged cars only as traffic demands it, and a shortage results when business picks up faster than ability to repair the cars. Whether or not shortages have ever limited the total supply of coal to the country, or have caused coal users to turn to other fuels, is a matter of conflicting opinion.

In a nuclear emergency, the Nation will have to rely initially, as indicated above, on the supply locally available, but there would be such great destruction of consuming equipment and plants that the supply would be generally adequate. Further supply should be available as quickly as it is called for by restoration of the economy. For other war or war-related emergency, the national capacity for producing

oil products seems to come close to equaling, or even exceeding, total wartime demand. This is without regard to imports, but so much judgment is involved, and the problems of wartime requirements and logistics are so complicated, that the subject needs deeper analysis than we can give it. Both coal-producing capacity and labor supply are large enough to meet emergency coal demand. Gas-producing capacity and electric-generating capacity are adequate. Information on wartime transportation capability regarding energy is scanty and conflicting, but seemingly there would be no dire problems within the United States itself. Ocean transportation encompasses military problems outside our purview.

COST AND TECHNOLOGIC PROGRESS

Implicit in the above commentary about the Nation's ability to meet its needs over the next 20 years is an assumption about the ability of continued technologic progress to hold costs within limits. In part this is a matter of faith, albeit faith based on the record. How much oil, gas, and coal will be produced, and how much electricity generated, are matters of economic decision, which resolve into incentives for exploration, research, and development and for investment in plant to transport what is produced or generated. Incentives are related to ultimate profits, which are related to costs. Information on costs is elusive and inconclusive, but at least for oil and gas jointly there seems to be little discernible trend either upward or downward in real terms (dollars of constant value). None of the three principal fossil fuels seems likely to price itself out of any major markets within the time span of this report. In any case the cost of oil from shale should place an upper limit on the price of crude oil, and the cost of gasifying coal a limit on the price of natural gas; all these will impose restraints on the price of coal.

The cost of transportation is a vital part of the delivered price of energy. The coal pipeline, the integral train, mine-mouth generation coupled with extra-high-voltage transmission, larger diameter oil and gas pipelines, and other developments should hold transportation costs down.

INTERFUEL COMPETITION

Use of coal has been going down in the face of an increasing national consumption of energy. The three fuels—coal, oil, and gas—compete with one another for the electric energy, space-heating, and process-heat markets; electric energy (including hydropower) competes with coal, oil, and gas for parts of these same markets.

Competition results from the ability and willingness of the customer to shift from one product or supplier to another. Many factors influence this freedom of choice. One is the physical character of the fuels. The solid nature of coal and the liquid nature of oil generate advantages and disadvantages for each, both with respect to cost in their competition with one another and with gas and with respect to esthetic preference.

A second factor is adequacy and assurance of supply, and a third is the delivered price. Delivered price is related to transportation. Cost of transportation is the reason why interfuel competition is so

severe in those areas having little or no native energy resources, as in New England particularly. Railroad transportation of coal comes high, compared to the cost of moving oil or gas, constituting on average throughout the United States more than four-tenths of the delivered price of bituminous coal.

All the major fuels, including coal, are produced and transported as though jointly with coproducts or byproducts. Electricity, too, is sometimes a joint product, and transportation also has its joint-product aspects. The economics of joint products influences the pricing of the main product.

One aspect of the influence of technology has been referred to above. Of more immediate relevance to competition is the technology of use, which has acted particularly to the detriment of coal. Prime examples are the change from steam to diesel railroad locomotives and the substitution of oil and gas for coal in home heating.

Fuel competition is related also to the propinquity of fuel source to market, which is a shifting circumstance, and of course to the common phenomenon of consumer preference.

A final factor is the framework of policies, laws, and regulations within which the competition operates, summarized separately below.

POLICIES, LAWS, AND REGULATIONS

Federal, State, and municipal governments all have laws and regulations relating to energy. The Federal Government leaves local energy problems to local regulation. In addition, the policies of foreign governments have their impact on American supply and demand.

Federal legislation and policy in the field of energy covers foreign trade, production of raw materials, electric power generation, production and sale of natural gas, transportation, research, taxation on production and use, maritime laws, and foreign relations. State and local regulations apply mainly to conservation of oil and gas and cover also taxation on mineral production and use, public utility regulation, and air pollution.

Policies of foreign governments relate to their control over the importation of American coal and to their reaction to U.S. restrictions on importation of oil and oil products. Canadian policy occupies a special niche, because of the contiguity of the two countries. The U.S. imports both gas and electricity from Canada, which imposes restrictions on the outflow of both.

Some policies, laws, or regulations tend to limit production and to raise price, some to lower price; some specifically restrict end use.

POLICY ISSUES

Twelve policy issues have been identified as justifying discussion. These include the sale of natural gas to industrial consumers under interruptible rate schedules, importation of residual fuel oil, importation of crude oil and products other than residual fuel oil, importation of natural gas from Canada, development of a domestic shale industry, the role of Government-sponsored research, domestic self-sufficiency, whether action is necessary to insure that U.S. emergency needs can be met from the Western Hemisphere alone, legislative or regulatory control of the use to which a fuel may be put, Government

encouragement of electric transmission interties, how to handle the problem of unemployed coal miners, and granting of right of eminent domain to coal pipelines.

Whatever policy direction may be followed with respect to each of these, various costs and gains are involved—to the Treasury, to the consumer, to the gaining and losing industries, and to society. Some of these gains can be quantified, mostly they cannot. In fact, it is not possible always to isolate them, or to trace out the specific effect of a policy action. Action taken may better one situation, worsen another. Questions that cannot be answered insist on intruding, such as: What is the cost to society when in the pursuit of some goal a desired product or service is denied? Or, what is the cost of withholding the fruits of technologic innovation or of dampening investment?

Energy policy relates to other policies, either explicitly or indirectly, and some energy policies indirectly affect policy in other areas. The important involvements are with transportation, taxation, trade policy, international policy other than trade, national defense, and various Federal programs, particularly atomic energy. Other areas of policy involvement include antitrust legislation, care and development of the inland waterways, space exploration, air pollution, labor, and urban redevelopment.

The three policy issues that are currently of most intense interest are:

Interruptible gas

In 1960 total interruptible sales totaled 2.1 billion Mc.f. Most of this is sold in geographic areas not economically served by coal, and some is sold for noncompetitive uses. In all, about one-fourth (or the equivalent of 22 million tons) is in direct competition with coal.

The price charged for interruptible gas is less than that charged for firm service and at least covers the cost of the gas itself plus the out-of-pocket costs of transportation and distribution. Thus this type of service makes a contribution toward fixed charges that would otherwise be borne by firm customers. In 1960 this fixed-charge contribution aggregated $400 million nationally.

Residual fuel oil

The use of residual fuel oil in the United States has remained fairly uniform over the past decade, but on the east coast, where most of it is consumed, net imports for domestic consumption have been rising and in 1960 were the equivalent of about 40 million tons of coal. Such imports come largely from the Caribbean where heavy fuel oil is the major refinery product. These imports affect the production of coal primarily in Pennsylvania, Virginia, and West Virginia.

Coal mine unemployment

The number of workers engaged in coal mining has been declining almost steadily from a peak of about 875,000 reached in the early 1920's. It is now only about 150,000. The number of unemployed is estimated at 100,000.

About half the decline has resulted from loss of markets and half from improvement in the efficiency of production. For bituminous coal the fractions are about one-third due to loss of market and two-

thirds to improved efficiency. The average miner produced 2,450 tons in 1960, as against 1,350 tons a year during the midforties when coal output reached its peak, and about 750 tons a year in the early twenties when employment reached its peak. Concurrent with loss of markets, coal-mining wages were rising and were among the highest in American industry, and this element of cost has been a major factor in pushing the industry into mechanization during the postwar period, in order to stay competitive.

Elimination of interruptible gas sales and of the importation of heavy fuel oil would increase employment in the coal industry, but for a number of reasons (among them that part of the vacated markets would be taken by domestic oil and by firm gas and that the current coal work force is used less than full time) the gain would be small—perhaps a few thousand men—in terms of the gross problem. Each million tons of added coal production would represent the employment of 400 miners at today's average output per man-day and at the average current workweek of less than 4 full days; at the current workweek but at the output per man-day projected for 1965, each million tons would represent the employment of 285 miners.

INDUSTRY AND CONSUMER POINTS OF VIEW

The point of view held by producers and consumers of energy as to what policy should be is as much a piece of information as is a table of statistics or description of a piece of technology. In order to provide as full a body of information as possible, we have invited the points of view of 12 groups, each representing either a producer of one or another form of energy or a consumer. These are included precisely as received. It would be a disservice to these groups to summarize their statements, for interpretation unavoidably would insinuate itself, and therefore we have not done so.

INTRODUCTION

The scope of this report

Senate Resolution 105 (87th Cong.) instructs the Senate Committee on Interior and Insular Affairs to undertake a study of the supply of and demand for fuels and energy in the United States. The study is intended as a basis for possible revision of fuels and energy policy, including the possibility of new legislation. The inquiry has three parts: (1) a study of the present and future energy requirements of the Nation and of its ability to meet those requirements; (2) a review of existing laws and policies with respect to their effect upon energy supply and demand; and (3) consideration of policy.

The first two parts are factfinding operations and constitute the subject of this report. The instructions given to the authors of it by the Senate Committee on Interior and Insular Affairs were simple and clear, as follows:

1. To prepare for the committee, within the objective of Senate Resolution 105, as accurate a story as possible, in simple and nontechnical language, about the economic and technical aspects of energy demand and supply in the United States.

2. In doing so, to deal with existing information only or such new information as can be assembled in short order.

. . . And its purpose

The first instruction constitutes a direction to sift out the fact from the nonfact in the existing body of information—to scrub the facts clean, so to speak. There are many persons who will say that the facts are clean enough as they are. That may be, as those persons see the facts. But Congress is not composed of experts in the demand and supply of coal, or oil, or gas; in the intricacies of electric generation, transmission, and use; in the potentials of atomic energy; in the possibility of needing and getting energy from the sun, or wind, or the tides, or of using heat brought up from deep in the earth.

What purports to be fact is not always indeed fact. The only bits of information that everyone can agree on are the bald statistics themselves and even that circumstance does not always hold. Often the so-called fact represents judgment, impression, informed guess, overstatement, prejudice, or sometimes plain fiction. Professional judgment and impression are invaluable when facts are short, but they are not a substitute for fact itself.

The element of prejudice must be particularly suspect. In relation to this study, there are two kinds: the honest prejudice generated by a person's loyalty to his profession or his firm, and the biases inherent in professional theory. There are various schools of thought on how to calculate mineral reserves, for example. Those who estimate reserves of coal, oil, and gas each believe that the occurrence and economics of his commodity are unique and demand unique definitions and criteria. A figure on reserves is thus not an immutable fact, but,

in the first place, involves considerable judgment and, in the second place, is conditioned by the business economics of the industry.

A second example is in the methodology of making projections. There are two major schools of thought on how projections are to be made, and each contains subschools. The adherents of each school are honestly convinced about the correctness of their methods, but however positive they may be, the figures they come up with are not fact. Considering the wide ranges in projections of future use of energy, for example, made by different experts, the figures certainly are not the kind of "fact" upon which Congress should properly be asked to anchor anything so serious and far reaching as national policy.

The first intent of this report, then, is to assemble the facts as meticulously as possible. Where facts run short and judgment must be used, the report points out where the judgment enters; where informed guesswork must be resorted to—and it is resorted to only where necessary—that is clearly flagged for the reader's attention. Where the facts are too scanty for even that, the reader is informed of that, too.

Volumes of information are available. If stacked one on top of another, the statistical compilations, analyses, and reports relevant to the present study would make a pile many feet tall. A list of those that have come to our attention appears as an appendix to this report. The amount of information of one kind or another is so impressive as to appear to obviate the need for time-consuming and costly new studies. Part of the purpose of this report is to find out if that is true—to find out if it is necessary too often to resort to guesswork in clarifying the economic and technologic basis of policy consideration.

The approach

The method used herein in approaching the purposes stated above is to analyze the energy needs of the United States and then to measure against them the supply of energy that can be made available. At the same time and within this framework, and in order to keep the study oriented toward its main purpose as an aid to policy consideration, the report keeps its eye on the gathering and analysis of information specifically needed to clarify the policy issues brought to the attention of Congress during the hearings on Senate Resolution 105.

Preparation of the report has exposed an assortment of additional policy issues. These are indicated. Indicated also are alternative approaches to these issues, an assessment of the costs of each alternative, and the extent, if any, that the various alternatives may violate the technologic and economic situation, in order that Congress may know of them in considering the political and social factors that it must deal with in policy determination.

How far into the future?

Senate Resolution 105 specifically refers to "prospective fuel and energy resources of the United States—and probable future rates of consumption thereof." How far into the future should one attempt to peer? The authors of this report have concluded that 20 years is a good compromise between impulse and reality. It is far enough

into the future to offer perspective for policymaking, yet is not so distant as to preclude reasonable assessment of future demand and satisfactory judgment as to the trends of the technology and economics of production. We can judge within reasonable limits, for example, what may be the technology of the production of coal, oil, and gas by 1980, and what may be the effects of this technology on costs of production, whereas anything beyond that date gets deeper and deeper into unnecessary speculation. At the same time, 20 years is distant enough to permit necessary adjustments in policy if such adjustments become necessary.

The year 1980, then, is taken as the terminal checkpoint for this report. The reader is cautioned to remember, however, that "1980" does not mean that specific year, but, rather, the general period of time clustered around it. The crystal ball available to authors of this report is not clear enough for them to predict what may happen in any given year. A glance at economic ups and downs exposed in any historical record prove how impossible that is. The reader may consider this to be an unnecessary caveat, yet experience proves that projections and the analyses made from them almost invariably run afoul of the public's inclination to hold the forecaster to the specific year.

Assuming that the study called for by Senate Resolution 105 leads to new legislation, it will, perforce, be a while before the legislation takes effect. This factfinding report must be studied, its information married to other considerations, and legislation studied, written, and debated. The new legislation and policy will apply to conditions as they then exist; 1960, the latest year for which statistics were available in preparing this report, and 1961 and 1962 the years in which the study was made and the report written, will be history. Accordingly, the authors have striven to project economic and technological conditions to, say, 1964 or 1965 as a base year.

PART I. ENERGY IN THE ECONOMY

USE PATTERNS

The ways in which energy is used at any given time are a function of the technology of use, the competitive ability of producers of the raw energy (including electricity) to deliver the energy to the consumer, availability of the raw forms, and preference of the consumer.

At any one time, one or another of these several factors dominate, at a different time another dominates. When wood was at hand for the taking, it was used, and the technology of use was adapted to the characteristics of wood. But when coal deposits were discovered and developed, coal's capabilities so far outstripped those of wood that the use technology was modified to suit—and the modification induced additional development of coal production. The growth of iron and steel production and that of coal also went hand in hand, as did, later, petroleum and automotive transportation. Petroleum brought gas with it, but use had to wait for a technology of transportation to be developed. With gas, consumer preferences were and are particularly important. Concurrently, gas was found to have unique properties that make it peculiarly useful for some purposes. Figure 1 shows the historical development of relative usage.

TABLE 1.—*Fuel consumption by sector, 1955*

[Trillion B.t.u.]

	Coal	Oil and natural gas liquids	Natural gas	Total
Industry	5,012	2,722	4,081	11,815
Commercial	896	763	603	2,292
Households	938	2,549	2,239	5,726
Transportation	333	7,430	254	8,017
Government	(1)	821	293	1,114
Agriculture	(1)	616	(1)	616
Miscellaneous	(1)	1,794	1,054	2,848
Electric generation [2]	4,242	630	1,384	6,256
Total	11,422	17,325	9,908	38,655
Total, 1961	10,226	20,412	13,426	44,064

[1] Included in other categories.
[2] Hydropower not included.

NOTE. Totals do not add due to rounding.

Source: Schurr and Netschert with minor adjustments; 1961 Bureau of Mines.

Table 1 shows the pattern of use by consuming sector. Of this pattern, a fifth to a fourth of coal use is nonfuel (for coke), some uncertain but small use of gas (for carbon black and petrochemicals), and an eighth of oil use (petrochemicals, lubricants, wax, coke, road oil, asphalt).

Coal is preeminent in the generation of electricity and is assumed by students of the subject to continue preeminent for some time in

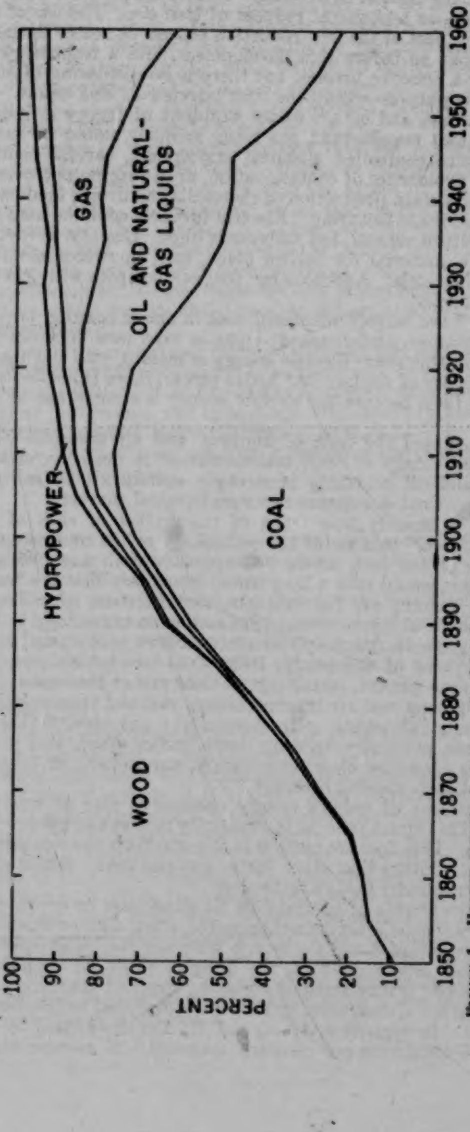


FIGURE 1. Energy sources as a percent of total energy consumption. (After Schurr and Netschert; 1900 figures based on Bureau of Mines data.)

this usage over the Nation as a whole. Coal is uniquely suitable, in the form of coke, as a chemical reducer of iron ore. The use of oil or natural gas in part of the iron-reduction process decreases the need for as much coke as before this development, and a technology is developing for a noncoke process, but there is no displacing of coke entirely for this purpose within the time purview of this report.

Coal, natural gas, and oil are major suppliers of energy in industrial processes that require heat, gas being uniquely suited for processes that require controlled chemical atmosphere, careful control of the heat, or avoidances of contamination, as in forging operations, heat treating of metals, production of chemicals and drugs, food processing, and glass manufacturing. Electric furnaces could be used for precise temperature control, but the cost is high. Gas also is ideally suited as a raw material for carbon black, used in rubber making, and for petrochemicals. And no other fuel can compete with gas for use in the field itself.

Oil and gas have largely displaced coal in space heating, largely because of consumer preference, and gas is even now limiting the growth of oil in this use. Electric energy is moving into this usage, but, except in areas of nuclear and hydro power, there is no displacement of fossil fuels because the electric energy is created out of one of them.

Oil has preempted the field of highway and air transportation, because the technology of such transportation is designed around liquid fuels, and oil currently is strongly entrenched in railroad transportation. Coal dominates the metallurgical market.

To attempt to specify how much of the market of each of the basic fuels is "safe," because of the technology of use or because of the properties of the fuel, would be impossible with any precision and in any event would take a long time. Some uses that are "safe" now may not remain so; for example, electrification of railroads could eliminate diesel locomotives. (See section on technology.) But the following gross fractions appear reasonable at present and up to the first checkpoint of this study, 1965: Coal—six-tenths (most of the electric utility market, metallurgical coke, use at the mines); oil five-tenths (highway and air transportation, railroad transportation for the present, lubricants, petrochemicals); gas—four-tenths or more (field use, petroleum refining, some carbon black and petrochemicals, uses requiring close temperature, atmosphere, or contamination control, some spacing heating).

About 35 percent of today's energy demand is free of interfuel competition. This figure represents essentially motive energy now met by liquid fuels. This does not mean that this market is noncompetitive within itself but rather that other fuels—gas and coal—cannot effectively penetrate it under today's technology.

At the other extreme of competition lie those uses in which coal, oil, and gas are immediately interchangeable, when dual or three-way equipment is maintained and the switch from one fuel to another can be accomplished immediately on the decision to do so. About 45 percent of the 802 utility stations reporting detailed information to the Federal Power Commission in 1960 were equipped to handle two or three fuels. In regions I, II-A, and III (as designated by this study), which constitute our "eastern seaboard," 27 electric utility

plants were equipped to burn only oil; 116 to burn only coal; 51 to burn oil and coal; 16 to burn coal and gas; 19, oil or gas; and 25 to burn all three. Thus, of the eastern seaboard's 256 steam electric plants about 45 percent burn more than 1 fuel, the same proportion as for the Nation. In the West, of the 56 utility steam plants in Texas 23 were equipped for oil and gas, the remainder for gas alone; in Oklahoma 13 out of 15 plants were equipped for more than one fuel; in California all 35 plants burn both oil and gas.

The percent of total energy market involved in this situation is impossible to quantify, however. Useful as this information is, it is deficient in that it does not indicate the extent of convertibility in terms of fuel use. For example, in an electric plant listed as being able to use more than one fuel, is the fuel-burning equipment capacity interchangeable? More important is the lack of information regarding nonutility plants, that is, other industrial plants, hospitals, schools, and apartment buildings. Some of these plants have dual equipment but there are no records of the number of installations or the quantity of fuel consumed.

In part of the energy market more than one fuel can technologically provide energy, but some added investment may be required.

As to the future, it is impossible to project economic conditions, consumer preferences, and technology with certainty, but it is certain that technology and taste will change as they have in the past and that these shifts will set up strong pressures for changes in conventional fuel-use patterns.

EXPENDITURES

The economy of the United States rests upon a small base of energy. National income originating in the energy industries is only about 4 percent of the total national income.

Consumers, manufacturers, and government spend but a small proportion of their incomes in the purchase of energy—household consumers about 5½ percent, manufacturers 1½ percent, and government possibly 3 percent. Despite the expanding use of energy these proportions have remained fairly constant.

By households

Household expenditures for energy may be classified as "internal" and "transportation." Internal energy is that used in day-to-day household operations within the physical confines of the home, in the form of gas, electricity, fuel oil, and coal. "Transportation" means private automobiles, and this need is met almost entirely by gasoline.

Surprisingly, however, while energy is so important in today's home, only a relatively small proportion of the consumer's income is devoted to that end. Consumer expenditures for such purposes have risen from $2.5 billion in 1930 to $11.4 billion in 1960, an increase of 360 percent (see table 2). While this represents a great many dollars, it nevertheless amounts to an actual decline in proportion of personal consumer income, from 3.3 percent in 1930 to 2.8 percent in 1960. This reduction is in face of the significant, indeed radical, changes and improvements that have come about in home energy usage over the past 30 years.

TABLE 2. *Expenditures for various forms of household energy*

[Dollars in billions]

Year	Personal income	Internal energy			Transportation, gasoline	Total consumer energy expenditures
		Electricity and gas	Other fuel	Total internal		
1930	$76.9	$1.2	$1.3	$2.5	$1.5	$4.0
1940	78.7	1.5	1.4	2.9	2.1	5.0
1950	229.8	3.1	3.2	6.3	[1] 4.9	11.2
1960	402.2	8.0	3.4	11.4	[1] 10.6	22.0

[1] Estimates by study group.

NOTE.—Totals may not add due to rounding.

Basic data from Department of Commerce.

Expenditures for electricity and gas alone have risen from $1.2 billion in 1930 to $8 billion in 1960; the percentage of income so represented, however, has risen only from 1.6 percent to 2 percent. These increases are largely due to more intensive usage of household utilities, the consumer having found more jobs for the utilities to do—to air condition, to incinerate, to dry clothes—but in part also because of the switch from coal to gas for house heating.

Expenditures for private automobile transportation in 1960 were about 2.6 percent of personal income, almost the same as the proportion spent for household energy. Spending on gasoline has risen sharply from $1.5 billion in 1930 to $10.6 billion in 1960, reflecting the added dependence of Americans on their family autos, although the portion of income devoted to this end has remained fairly level. Part of the increase is due to taxes and inflation.

All expenditures by the individual consumer, both for household use and for transportation, represented 5.4 percent of his income in 1960, as compared with 5.2 percent in 1930.

By manufacturers

In 1958 manufacturers spent slightly over $5 billion on purchased fuels and electric energy for heat and power, which is substantially less than was spent by households. Figures for earlier periods were $3.3 billion in 1947, $1.3 billion in 1939, and $1.8 billion in 1929. Fuel used for other than fuel purposes and for conversion to other energy forms are not included in these figures. (The years used here differ from those in the section on consumer use because of the availability of different statistical series.)

The Census of Manufacturers' reports show that manufacturing firms spent about 1.5 percent of their revenues in 1958 for fuel and electricity; in 1947 it was 1.9 percent. This proportion ranged from 3 percent to 5 percent in the process industries (chemicals, stone, clay, and glass, and primary metals) down to small fractions of a percent in printing, apparel, and other industries where major proportions of expenditures go to labor and materials.

By the Federal Government

The Federal Government is a substantial user of energy for heating, cooling, and lighting the buildings it occupies, to power its motor fleet, and in other areas. In fiscal 1961, the General Services Administration spent about $7 million for natural gas, oil, coal, and for steam

as such, and $16 million for electricity. The Post Office Department spent an additional $22 million. The General Services Administration, the Post Office Department, and other agencies also lease or rent buildings, the energy requirements for which, while for the use of the Government, get reflected in statistics on the private sector.

Data on purchases of gasoline are too spotty for meaningful summary. The Post Office Department itself spent $13 million for gasoline and motor oils. In 1960 the Federal Government owned more than 213,000 vehicles that used about 214 million gallons of fuel.

In the Government's construction program some of the work is by private concerns so that there, too, energy requirements are in part reflected by the private sector.

A second category of energy use by the Government relates to the Government's role as a supplier of electricity. The steamplants of the Tennessee Valley Authority in 1960 burned 18.6 million tons of coal for which it paid about $83 million, and the TVA operations as a whole supplied Federal agencies with electricity bearing a price tag of $110 million.

A third category of Government energy expenditures relates to the military and atomic energy programs. Military expenditures exceed $1 billion a year for petroleum and its products and $20 million a year for coal, but we have found no figures for outlays for gas and electricity. The Atomic Energy Commisison spent about $232 million for electricity in fiscal year 1961 and an additional but unknown amount for fossil fuels. It was the principal recipient of energy from the Tennessee Valley Authority.

It appears that about 9 percent of the Atomic Energy Commission's total expenditures in 1960, and 1 percent of the Post Office Department's expenditures, was for energy. The figure for the military program, which is less energy intensive than the AEC operation but much more energy intensive than the Post Office operations, would lie somewhere between.

Since the remainder of Government probably falls between the military and the Post Office in terms of intensity of energy use, one may judge that between 1 percent and, say, 3 percent of the Government's operating expenditures are spent for energy.

6. The ultimate grand total of recoverable gas may be in the neighborhood of, say, 1,250 trillion cubic feet. This amount is compounded as follows:

Recoverable from proved parts of known reservoirs: 260 trillion cubic feet.

Recoverable from extensions to present areas and from pools yet to be discovered: Potentially 1,000 trillion cubic feet.

7. How much gas will in fact be discovered and recovered is anybody's guess, depending in part on money invested. The above figures do, however, give some appreciation of future possibilities. Most of the United States is favorable for discovery.

GAS IN COAL SEAMS

Most coal seams contain methane of a quality—1,000 British thermal units a cubit foot—equivalent to natural gas. The gas is contained in the pores and cracks.

Methane is recovered commercially from coal seams in Belgium, Germany, and France, and a little has been recovered and used locally in our own Appalachian area. Gas has always constituted a problem in coal mining, of course, and the mechanization that has taken place in recent years has aggravated it. New faces of coal are exposed so rapidly that the quantity of gas seeping from the coal makes ventilation increasingly difficult and costly, and thought is being given to removing the gas before mining. The Bureau of Mines has experimented on methods of doing this.

A ton of coal (except for the parts above water level or near the surface, from which the gas has leaked out) may contain as much as 2,000 cubic feet of gas. Thus the Appalachian field, which contains some 300 billion tons of coal in place (155 billion tons recoverable; see section on "Coal Reserves"), may contain possibly 600 trillion cubic feet, or twice the current estimates of proved gas reserves. Most of the gas, however, is perhaps so pore-locked as to be released only when the coal is crushed. The imperfect information we have suggests that the average content recoverable without crushing may be no more than 200 cubic feet a ton. At that rate, the potentially usable methane contained as such in the coal seams of the Appalachian region would total 60 trillion cubic feet. For the entire United States the total would be, say, 350 trillion to 400 trillion cubic feet.

COAL

Estimates of the coal reserves of the United States—in the sense of the tonnage that can be mined under existing mining practices and economic conditions and constituting the basis of investment—have been nonexistent.

The U.S. Geological Survey has periodically reported on what it calls the "coal reserves of the United States," but the term is defined as meaning estimated quantities within stated limits of bed thickness and depth below the surface without direct economic connotation. The total figure is said to include the coal in beds 14 inches or more thick to depths 3,000 feet below the surface. The figure is obtained by first estimating the total amount of coal originally in the ground and then reducing this by production to date and by an estimate of

coal lost in mining, to yield an estimate of the coal still remaining. The remainder is divided by 2 to give a figure called "recoverable reserves," this ratio being based on an analysis of a wide variety of studies on individual mines, counties, States, and individual coal seams.

The 50 percent considered recoverable excludes coal left in restricted areas around oil and gas wells and under towns, railroads, roads, and streams, as well as coal left in pillars to support the overlying rock, in thin adjacent seams left unmined here and there, in local areas of complex geologic folding and faulting and thus too costly to mine, coal lost in cleaning, and a small amount of refuse waste. Actual recovery in individual mines has ranged from less than 40 percent to as much as 80 or 90 percent.

The Geological Survey's estimate of recoverable coal, as of January 1, 1960, totals 830 billion tons.[6] The distribution by regions is as follows:

	Millions of tons	Percent of total
Region I of this report, New England (see map)	Trivial	
Region II, Appalachian region	155,840	19
Region III	90	
Region IV	139,300	17
Region V, gulf coast	20,680	2
Region VI (lignite and subbituminous)	347,590	41
Region VII	85,070	10
Region VIII, Pacific Southwest	Trivial	
Region IX, Pacific Northwest, including Alaska	79,200	10

This figure on recoverable reserves has been, and is, quoted as being equivalent to 2,000 years of production at the current rate. The arithematic is faultless but the calculation has little meaning, first because current rates of output are ephemeral, and second, because there is no indication as to how much it would cost to get the coal produced.

Of more immediate importance is the amount of coal available to support immediate and near-term production—the composite national tonnage of coal held by individual producers upon which they have based, or are willing to base, commmercial operations. Of even more immediate concern is the part that has been prepared for mining, the part, that is, into which entries have been driven or equivalent work performed in accordance with a determined mining system and awaiting only introduction of labor and equipment for production to begin. Such information has to be known for each method of mining—strip mining, auger mining, underground mining.

The Department of the Interior[7] reported in 1960 that 20 billion tons would be available at 1958 prices and costs over the next 40 years. As indicated below, this estimate exposes a high degree of expert judgment, but still it does represent judgment alone and does not provide the kind of assured knowledge needed to assess the strengths and weaknesses of the coal industry, particularly its ability to meet a sustained emergency. The necessary information resides only in the files of industry, and the National Coal Policy Conference has circularized the independent coal producers in order to get it for this study.

[6] Averitt.
[7] Joint Committee on Atomic Energy, Robert McKinney, vol. 4, p. 1520.

FIGURE 16.—Coal fields of the United States, exclusive of Alaska. Prepared by the Geological Survey, Department of the Interior

Response was received from producers representing, from district to district, 25 to 100 percent of annual output but excluding captive operations. Extrapolating the returns to 100 percent of coverage gives the estimates shown in the accompanying table, with grand totals of 20 billion tons at 1960 prices (of which 3.75 billion tons are strip and auger coal) and 35 billion tons at a price 25 cents a ton higher (of which 5 billion tons are strip and auger coal).

Estimated coal reserves of the United States, 1961

Region	Total reserves				Strip and auger reserves			
	At 1960 prices		At a price 25 cents a ton higher than in 1960		At 1960 prices		At a price 25 cents a ton higher than in 1960	
	Reserves (millions of tons)	Percent of total	Reserves (millions of tons)	Percent of total	Reserves (millions of tons)	Percent of total	Reserves (millions of tons)	Percent of total
II	14,000	73.3	27,000	82.4	2,100	56.0	3,400	68.3
IV	4,000	21.3	5,000	15.2	1,050	27.9	1,200	23.1
V	5	0	5	0	5	.1	5	.1
VI	500	2.7	600	1.8	500	13.3	500	9.5
VII	100	.5	200	.6	100	2.7	100	2.0
IX	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Total (rounded)	20,000	100	35,000	100	3,750	100	5,000	100

1 Not reported.

We often hear the statement that the demands of World War II nearly exhausted the strippable reserves in the Appalachian region. The following table shows a breakdown of the strip and auger reserves in that region.

Reserves of strip and auger coal in the Appalachian region, 1961

	At 1960 prices		At 25 cents above 1960 prices	
	Million tons	Ratio of reserves to 1961 production	Million tons	Ratio of reserves to 1961 production
Pennsylvania, Maryland, northern West Virginia	100	4	300	11
Southern West Virginia, east Kentucky, Tennessee, Alabama	1,500	93	1,700	105
Ohio	200	8	1,100	44
Western Kentucky	300	17	300	17
Total and average	2,100	25	3,400	40

The 4-year and 11-year "life indexes" shown for Pennsylvania, Maryland, and northern West Virginia, which are the States whose strip and auger mines have been feeding fuel into the Eastern States, have no significance, however, as to whether reserves are running out or not. We have no past estimates of reserves against which to compare them in order to see if a short life index is a characteristic of that part of the coal industry or, if on the contrary, the index has been progressively decreasing as an indication of approaching ex-

haustion. We can be certain that continued improvement in coal mining technology and productivity (see chapter on "Technology") will have made most or all of the additional 200 million tons minable, at prices equivalent to those of the present, well before the 4-year quantity runs out, and will have made minable also several hundred million additional tons at a then moderate increase in price. At about 1965, then, reserves of surface coal in the northern Appalachian region, minable at 25 cents above the then price, should be some 500 million tons, with additional tonnages made available if improving technology can make possible the stripping of thicker overburden or deeper extraction with augers.

In any event, any possible exhaustion of strip reserves in the northern Appalachian region might be made up from nearby producing areas. The significance of strip reserves is not that they have any special quality, but (*a*) that in general they yield lower cost coal than underground reserves and (*b*) that output from surface mines can be expanded, in an emergency, faster than from underground mines.

FISSIONABLE MATERIALS

The Atomic Energy Commission has reported to the President that reserves of uranium in the United States in June 1962 were 175,000 tons of U_3O_8 minable at the price of $8 a pound. A "significant but undeterminable" additional tonnage would become available at $20 a pound, and perhaps as much as 5 million tons would be available at $50 a pound. These figures compare with a 1961 U.S. production of 18,000 tons U_3O_8 and a total 1961 Free-World production of 36,000 tons.

The amount of applicable energy that these reserves represent depends on the efficiency of the atomic reactors in which they may be used. (See section on technology.) The 175,000 tons of reserves mentioned above could be the equivalent of as little as 10 billion tons of coal or as much as 500 billions tons.[11] That is, as raw energy material $16,000 worth of U_3O_8 (1 ton) is the equivalent of at least $200,000 worth of coal (some 40,000 tons at average U.S. mine price of $4.85 a ton). The 5 million tons of U_3O_8 available at a higher price are equivalent to between 200 billion tons and 10,000 billion tons of coal. The figures are hard to grasp; perhaps they can be brought into perspective by noting that the minimum figure of 10 billion tons of coal equivalent is more than the amount of coal used in the United States in the past 20 years, whereas the top amount is six times as much as all the huge coal resources of the country. (See preceding chapter on coal resources.)

Additional quantities of U_3O_8 could be found if sought, and there are also quantities of thorium ore. Considering the magnitude of the above figures, however, for the purpose of this report there is no need to speculate on how much additional U_3O_8 could in fact be found, or to be concerned about the actual figures on thorium.

A related speculation comes to mind, namely, whether the money and effort that would be needed to find more uranium might better be spent in improving reactor efficiency, but the speculation tends to answer itself. Human nature being what it is, improvement in reactor

[11] Joint Committee on Atomic Energy, Robert McKinney, p. 38.

Labor

COAL

The labor used in coal mining ranges from the unskilled to the highly skilled. Five States—West Virginia, Pennsylvania, Oklahoma, Illinois and Arkansas—have requirements regarding apprenticeship. In those States no man can be employed in a responsible mining job until he has a miner's certificate, obtainable after a year of employment, and has taken an examination. Pennsylvania requires 2 years of training for anthracite miner, and requires a certificate for anyone who handles explosives, underground or surface. In addition to the skilled miner, there are also the trained maintenance workers and supervisors. Labor supply in coal production, then, covers both quantity and quality or occupational composition.

There are three continuing official sets of statistics regarding coal mine labor: (1) by the Bureau of Labor Statistics; (2) by the Bureau of Mines; and (3) by the Bureau of Employment Security. The Bureau of Labor Statistics' figures are based on payroll information and cover both all employees and, separately, production and related workers through the working foreman level. The Bureau of Mines' figures are gathered in connection with the Bureau's mine-accident interests and do not cover store and office workers. The figures of the Bureau of Employment Security are compiled in connection with unemployment insurance laws and cover everyone on the payroll including top management but excluding the self-employed and officials of unincorporated firms. The first two tabulations are not clear as to the extent to which they include working proprietors. There are about 5,000 mines employing less than 10 men each and in which, presumably, the owner himself works. The three series differ one from the other in a way not always related to coverage; for example, in 1959 the Bureau of Mines' figures were 11,000 larger (7 percent) than the broader ranging Bureau of Labor Statistics' figures.

According to the Bureau of Mines, the average number of employees in bituminous coal mining in 1960 totaled 169,400. This is the lowest number for 70 years at least. (See fig. 36.) Of this total 84 percent were employed at underground operations, 15 percent in strip mining, and 1 percent in auger mining. Regionally, 86 percent worked in region II of this report (the Appalachian field), 9 percent in region IV (the Midwest coal field), 3 percent in region VII, and less than 1 percent the other regions.

The average number of men employed in anthracite mining in 1960 was 19,051, all of them in Pennsylvania. Eight-tenths were employed at underground operations and two-tenths in strip mining.

The total coal mine labor force is thus about 0.3 of 1 percent of the total U.S. labor force.

Three-fourths of the coal labor force, bituminous and anthracite combined, is union-affiliated, one-fourth nonunion.

Fewer and fewer young men are applying for miner's certificates, and as a result the average age of coal miners has been rising—estimated from 40 in 1951 to 45 in 1960.

There is also a substantial number of unemployed miners. In a survey made for this study by the bituminous coal industry, it was reported that during June 1961, in the seven ranking coal States plus

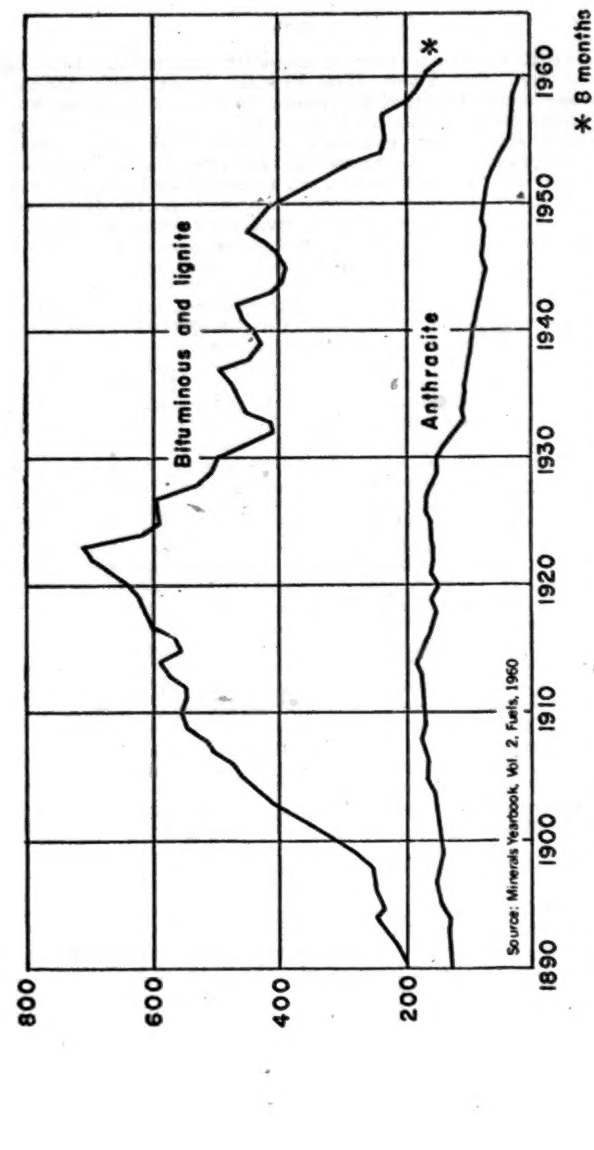


FIGURE 36.—Number of men employed in coal mining in the United States has been decreasing since the twenties, 1890–1960.

Tennessee (which eight States account for about 90 percent of U.S. production), there were 129,530 men employed and 32,760 unemployed, for a total labor availability of 162,290 in those eight States. (These figures include production workers and shopmen—i.e., hoistmen, carpenters, machinists, electricians, and the like.) There is an additional number of unemployed who do not appear on unemployment rolls and for whom, therefore, the reporting agencies had no record.

No parallel figures are available relating to the other coal-producing States, but the State coal associations in six of them, including the Western States, report an excess of available underground labor. A few having strip-mining operations reported also an excess of strip-mining employees, and a few reported surplus auger mining employees.

The United Mine Workers of America estimate that throughout the country unemployed coal miners (bituminous and anthracite) number 100,000.

In addition to the production workers and shopmen, a substantial number of persons are employed in professional capacities (surveyors, accountants, lawyers, and the like) and on the clerical and sales forces. According to some 1950 figures from the Bureau of the Census—the latest presently (February 1962) available in this regard—these may total an additional 10 to 15 percent, or some 15,000 to 25,000 persons.

Very little information is available as to the skills of those employed. The 1950 census figures give a detailed breakdown among the shopworkers but make no useful breakdown as to production skills required in operating complex mining machinery and in mine maintenance.

Although there appears now to be about 25 percent more labor than is being used, it does not follow that this 25 percent is usable. We do not know where their skills lie. If, for example, expanded production should be called for from strip mines, it may be found that there is a shortage of dragline or shovel operators; if the expanded production is attempted from underground mines, there may turn out to be a shortage of men who can operate a mechanical loader, a continuous mining or cutting machine, or who know how to put in roof bolts or to lay track.

One may assume that the unemployed workers represent all the skills involved, and in representative proportions, but the assumption is not necessarily a safe one.

Opinions from coal people vary from 1 week to 3 years as the time necessary to train a person adequately to do an underground job. The extreme range in time is due both to difference of opinion and to the nature of the job, but most coal people believe that after the year necessary to obtain a miner's certificate (2 years in anthracite mining) the average person could perform any assigned production job. Training for a supervisory capacity or for maintenance work on complex machinery takes longer. On the other hand, a man who can operate a dragline ought in short order to be able to operate a coal cutter or any other piece of equipment; the average mechanic should not need much training to be able to repair complex mining machinery. Admittedly, it may take a little extra time for a person to be-

come alert to safety factors, such as the character of the roof or t possible presence of gas.

Relation to markets and productivity

Two factors have influenced the decline in the labor force show in figure 36: (1) less production and (2) increased output per work (See chapter on productivity.)

Production of bituminous coal and lignite was 27 percent less i 1960 than it was in the year of peak employment, 1923; assumi no change in efficiency of production the 1960 output would th have taken 27 percent fewer men, or 190,000 less than in 1923. Th is the reduction in the labor force that may be attributed to small output. The 345,000 remainder of the total reduction of rough 535,000 men (704,800 to 169,400) would be the part attributable increased output per man.

The vigorous efforts of the bituminus coal industry to improve th output per man reflects the intention to keep the cost of producti under control. In 1960, wages at $3.15 an hour were higher than i any other American industry; the next highest were in petroleu refining, at $3.02 an hour.[a] Despite the fact that bituminous co miners worked on average a smaller part of the week than other labo weekly earnings also were near the top.

In anthracite mining increasing output per man has been less c a factor. The peak year of employment was in 1914. Productio in 1960 is 79 percent less than in that year. Again, had efficiency c production remained constant, 1960 production would have require 79 percent, or about 140,000, fewer men. The total decline in em ployment has been about 160,000, meaning that in anthracite minin employment has gone down about 20,000 because of improved outpu per man, and 140,000 because of reduced market.

OIL, GAS, AND ELECTRIC UTILITIES

Gas pipeline companies and electric and gas utilities have devel oped comprehensive employment information, largely because of th stringent reporting requirements imposed on regulated industries For petroleum, the information is less complete.

The following table shows 1960 figures:

	Employees	Percent of U.S. labor force
Petroleum and natural gas productions	288,000	0.
Petroleum refining	182,000	.
Gas pipelines and distribution	205,000	.
Electric utilities	340,000	.
Total	1,015,000	

Source: Bureau of Labor Statistics, *Earnings and Unemployment*, February 1961.

The 470,000 employees shown in petroleum and natural gas pro duction and in refining do not include those engaged in various phas

[a] U.S. Dept. of Labor Monthly Review, March 1962.

The economic advantages in the concept of "transporting coal by wire"—the burning of the coal in utility plants located at or near the mine and then moving the electricity to the point of use—lies in the fact that the average utility plant has to transport about 10,500 B.t.u.'s in the form of coal to generate only 3,400 usable B.t.u.'s in the form of electric energy, as explained in the chapter on "Technology."

CONCLUSIONS

The preceding pages on transportation contain largely descriptive material that speaks for itself for the moment and that will take on major meaning only when brought together with other material in comparing the demand for energy with the supply available (pt. VI of this report) or in discussing specific policy issues (pt. VIII). A few conclusions emerge, however, that are of direct policy relevance.

1. Except for a small amount used in the process of production, all energy, of whatever kind—coal, gas, oil and its products, or electricity—has to be transported from point of origin or production to point of use.

2. Although there has been a general downward trend in the tonnage of coal shipped by rail over the past decade and a half, and a steady decline in the percentage of coal shipped by rail, revenues from coal traffic have stayed firm as a result of adjustments in freight rates.

3. The ratemaking system used by the railroads permits adjustments in some circumstances to allow coal to be marketed at a price that can compete with oil or gas at the same destination. The cost of producing coal—a nontransportation factor outside the control of the railroads—is thus a factor in railroad freight rates.

4. The ratemaking system used by the railroads considers also the ability of different mines in the same general region to compete in common markets, and thus takes coal-mining costs into account to a still further degree. Differential adjustment has aspects of preferential adjustment.

5. On a U.S. average, railroad freight charges for at least 20 years have constituted more than four-tenths of the delivered price of coal.

6. The shortage of cars to move coal, complained about from time to time in the Appalachian and midwestern coal regions, is the result of business decision on the part of the railroads. The railroads repair damaged cars only as traffic demands it, and a shortage results when business pickup moves faster than the ability to repair the cars.

7. Whether or not such car shortages as there have been have impaired the total supply of coal to the country, or have caused users to turn to competing fuels, is a matter of opinion—there are no statistics or other documented information on the subject.

8. While in peacetime barge transportation along the waterways of the country is simply a competitive form of movement, truck haulage is a necessary part of the transportation systems for coal and oil.

9. The low direct operating cost of pipeline transportation, and its ability to deliver a product continuously, is directing attention to the pipeline transportation of coal as a competitor of railroad transportation. This development could materially influence the market outlook for coal, but its ultimate success will depend not only on pipeline technology but also on railroad technology and rates and on the political problem of eminent domain for right-of-way.

10. The economics of transporting electricity and natural gas are similar in that each must arrange to meet high peak requirements, both daily and seasonally.

Emergency

We are dealing in this chapter with the same attempt at before-the-fact interpretation as in the chapter on emergency requirements. Despite the fact that the problem of emergency transportation has been under scrutiny since 1947, information on it is scanty and in some instances conflicting, and the President has directed the Secretary of Commerce (by Executive Order 10999 of February 16, 1962) to come to grips with it. The paragraphs that follow should be read within these qualifications.

COAL

The emergency transportation of coal poses a problem that other forms of energy do not, in that it competes with other bulk commodities that also use open-top cars, barges, and trucks: ores of urgently needed metals, sand and gravel for concrete and other construction, and crushed stone also for concrete aggregate, for railroad ballast and highway construction, and in smelting and other industrial processes. Information on emergency demand for these other items is lacking. A second lack is information on how much unused capacity is available for emergencies.

Heavy loss of rolling stock and facilities in prime *nuclear* target areas can be expected, but a large number of classification yards, truck terminals, and inland water terminals are in target areas of low priority—according to American transportation experts' version of the enemy's plans. Yet an attack may well be preceded by a well-timed wave of sabotage, and inasmuch as transportation is always a key focus of enemy attention, damage may be greater than suggested above. In any event, transportation equipment by its nature is always widely dispersed, and only a relatively small number of pieces will be in any presumed target area at any one time. The overall capability of the railroads, bargelines, and truck fleets is thus expected to survive a nuclear attack better than the consuming, oil refinery, and electric-generating segments of the economy. Even assuming heavy loss of rolling stock and facilities in target areas, the movement of the reduced requirement could be met, it is expected, with surviving equipment and facilities through reduction of turnaround time, alternate routings, and other measures all of which are routine in the transportation industry, such as close coordination of rail, motor, and water movements, "piggyback" operations, and cannibalizing damaged facilities and equipment. Equipment and rolling stock from the construction and ore-mining industries, both of which would be shut down for some months following an attack, could be utilized.

Locomotives offer reasonably good shielding against fallout, and tests suggest that trains should be able to travel anywhere soon after an attack. The tests suggest also that, except in areas of most lethal fallout, maintenance and repair crews could enter facilities like classification yards and repair shops within a matter of weeks.

Coal movement through the Great Lakes and by the inland waterways would be crippled if navigation locks and bulk handling facilities

nonreactive to the waste solutions; (3) to pump them into exhausted oil sands or other deep permeable formations; (4) to dump them far out at sea or on the polar icecaps; and (5) to package and shoot them into outer space. Serious obstacles are inherent in each of these. For example, in pumping into geologic formations, the chemical reaction between the waste solutions and the environment is likely to be such that the pore spaces may become quickly clogged and the whole operation brought to a halt. Disposal at sea is faced with a grand ignorance about ocean currents and the ecology of marine life.

The National Academy of Sciences has had a panel working sporadically on these problems since 1954. Research on matters of this kind moves slowly, and no one would dare predict when the problem of waste disposal will be solved. One point of view is that before the problem becomes crucial an isotope technology will have developed that will require all the Sr^{90} and Cs^{137} produced.

Corporate Concentration

In tune with industrial development throughout the country, a relatively small number of coal, oil, and gas companies account for most of the production. In logic and by analogy with other mineral industries, a few companies probably also employ the bulk of the labor, although because of mechanization in the large coal operations and because large operations are generally the more efficient, the concentration of labor is not so great as is concentration of production. If statistics are available on this subject, they are widely distributed and not readily obtainable. It is probably true also that the companies that produce the most own most of the reserves as well, but only speculative figures on reserves of coal, oil or gas company by company are available.

A similar corporate concentration exists in the electric generating industry. Electric power is generated relatively close to where it is needed—or in the case of hydropower, where good sites exists—and is used within a limited radius where it is generated, so that the corporate concentration that exists is related more to population and industrial concentration and to facts of Nature than, as in coal, oil and gas, to business decision.

Yet, while there is this corporate concentration in the energy industries, these industries are not as concentrated as many other industrial segments in America. Notable examples are the automobile, tire-manufacturing, gypsum-products, aluminum, steel, and acid-manufacturing industries, in which no more than four companies account for eight-tenths or more of shipments.

COAL

The 5 ranking coal companies in 1960, out of a total of roundly 7,500 (0.07 percent), produced almost an even fourth of the year's total output. The top 10 companies produced an even third, and the top 25 produced half. The other half was produced by the remaining 7,400 and more. See figure 61.

Some coal operations are captive, i.e., the mining companies are owned by steel companies and public utility systems and produce coal

for the parent company as needed. If these operations are excluded, the concentration is a little less acute.

The concentration by company is paralleled by a concentration in mines. Small operations have been and are being combined into large ones, inefficient small mines get shut down, and efficient mines are enlarged. Despite this, the total number of mines in operation has generally increased. Figure 65 compares the situation in 1960 with that in 1910 when coal production was on the way up and total output was the same as in 1960, at 416 million tons. Although there were a third fewer mines at that time, they were more uniform in size. Thus while 10 percent of the mines yielded 44 percent of the year's output in 1910, in 1960 this output was provided by only 4 percent of the mines. Or while 10 percent of the mines in 1910 yielded 44 percent of the output, 10 percent in 1960 yielded fully 80 percent of the output.

We do not have full information for the individual coal-producing regions. The bit that is available indicates that the national averages obscure some important regional differences. Nationally, mines producing less than 50,000 tons a year each constituted, in 1960, 80 percent of the firms but contributed only 16 percent of output. But mines of that size produced fully 56 percent of the tonnage in Tennessee, 47 percent in Virginia, and 35 percent in eastern Kentucky.

OIL

In crude oil production (again see fig. 64) a fourth of the output (1959) is by the five ranking companies. The top 10 companies produced 37 percent, and the top 15 companies 44 percent.

In refinery operations four-tenths of the output (1959) is by the first five companies. The top 10 companies produced more than six-tenths, and the top 15 companies three-fourths.

GAS

Because of the large investment required, few companies can afford to get into the gas transmission business. Moreover, the economics of scale favors large firms. As a consequence, corporate concentration is high, the highest, in fact, among this group of industries, 15 companies out of 106 (14 percent) in 1960 accounting for 84 percent of the industry's total gas sales. In gas distribution, in contrast, 84 companies (out of 1,324) accounted for this same 84 percent of the sales.

The only figures available on corporate concentration in gas production are for 1954. According to them, and by strange coincidence, concentration in this industry—as measured by number of firms and percent of output or sales—is almost precisely the same as in the gas distribution industry. Gas distribution is much the more concentrated of the two as measured by percentage of firms.

ELECTRIC GENERATION

Concentration among companies and systems generating electricity closely parallels, up to about half of total output, corporate concentration in gas distribution and crude oil production. The top 5 companies or integrated systems account for nearly a fourth (23 percent in 1960)

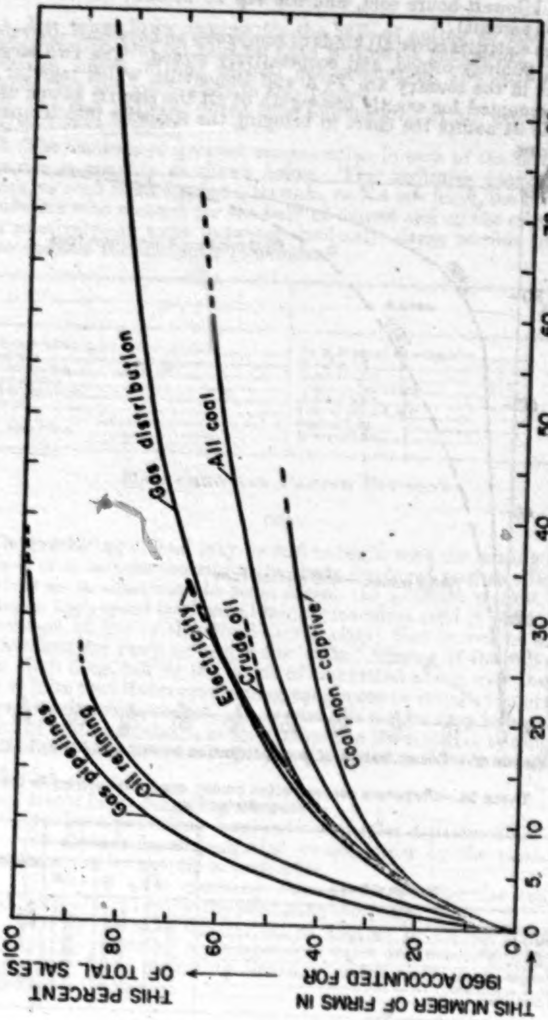


FIGURE 64.—A relatively few companies account for the bulk of output and sales in American energy industries.

of the kilowatt-hours sold, and the top 20 account for more than half (53 percent).

These statistics cover all kinds of companies and systems—privately owned, publicly owned, and cooperatively owned. The two largest systems in the country are TVA and Bonneville, which together in 1960 accounted for exactly one-eighth of all the electric power used.

Table 24 assists the chart in bringing the statistics into comparative focus.

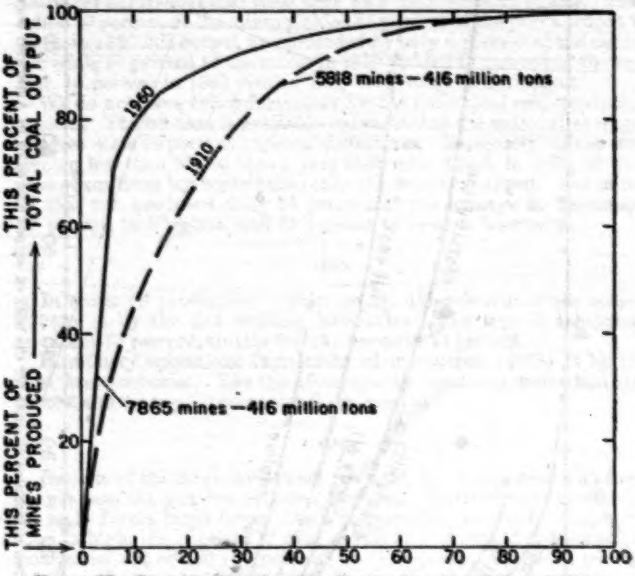


FIGURE 65.—Concentration of coal production by mines, 1960 and 1910.

TABLE 24.—*Corporate concentration among energy industries in the United States*

	Percent of total sales			Total firms
Number of firms	8	15	20	
Gas transmission	30.9	54.2	96.1	108.
Oil refining	39.4	75.1	87.3	172.
Gas distribution	23.4	46.6	56.8	1,224.
Gas production	23.0	47.0	59.0	About 11,000.
Electric generation	23.2	43.7	58.7	3,600.
Crude oil production	23.0	44.3	52.5	About 11,000.
Coal production	24.5	39.5	49.0	1,112.[1]

[1] Producing 100 tons or more a day. Total number of companies is 7,300.

CONCLUSIONS

1. Far fewer firms account for the bulk of output or sales in gas transportation and oil refining than in electric generation, gas distribution, crude oil and natural gas production, and coal mining, which four are much alike in this respect.

2. The coal industry is the least concentrated of all, gas pipelines the most concentrated.

3. The compass of greatest concentration in each of the several industries is roughly as shown below. This indicates generally the break, as read from figure 64, between, on the one hand, the few large producers who account for the bulk of output and on the other hand the relatively—in some instances absolutely—large number of firms who account for the small remainder.

	Number	Percent of output
Gas transmission	Up to 11 out of 106 companies	75
Oil refining	16 out of 172	78
Gas distribution	11 out of 1,324	40
Gas production	11 out of about 11,500	40
Electric generation	11 out of 3,600	40
Crude oil	8 out of about 11,000	34
Coal	6 out of 7,200	36
Coal, noncaptive	11 out of 7,200	34

MARKETING AND PRICING PATTERNS

COAL

The marketing of coal may be said to begin with the mining itself. This is true because the mining methods employed may so affect the product as to determine to some extent the ultimate market. For example, high-speed mechanical mining machines tend to yield a high percentage of fine or slack coal (small sizes) that cannot be sold in the markets for lump or larger size coals. Mining of the full seam, as is often done, taking the bands of impurities along with the coal, may require that elaborate cleaning equipment be installed in order to make a marketable product. In reverse, the market may influence the choice of mining methods, as for example, in the selective mining that is sometimes used in order to get the quality of coal for making coke.

Marketing

Coal is sold in the following ways:

(1) By a producing company's own sales departments.

(2) By a sales organization owned either by the producing company or by a group of producers.

(3) By a sales company that owns or otherwise controls directly or indirectely, the producing company.

(4) By the sales department of another producing company.

(5) By a broker or independent sales organization who acts as agent for a producing company under contract or who may purchase for resale.

(6) By a captive mine directly to the owner's consuming plants. An individual company generally relies on a single method in selling most of its output but uses a variety of methods in effecting total sales.

Only a relatively few producing companies are large enough to afford a sales department or an affiliated sales company. Most find it more economical to use the services of independent sales organizations, which provide for a group of small producers the same services provided by the sales department or sales affiliate of a large integrated company.

Consumers who have a railroad siding and are able to receive at least a full carload of coal, and those who are located on navigable waterways, purchase directly from the mine's representatives. Consumers who do not have such facilities usually purchase coal from a retail coal merchant. This had led to a general categorization of customers as either "on-track" or "off-track" accounts. There is also an ever-increasing volume of coal moving by truck and barge directly from mine to consumer. In recent years, some consumers have located plants adjacent to coal mines where coal can be delivered by belt conveyor or by other suitable means direct to the consumer's plant. There are other special situations, such as the coal pipeline in Ohio, but these are not now a part of the general marketing pattern.

The retail market includes, aside from a relatively few home users, some industrial users and such other users as hospitals, apartment houses, schools, and office buildings, where coal-burning equipment requires the smaller sizes of coal. In 1960, less than 10 percent of the total bituminous coal and 70 percent of the anthracite consumed in the United States was classified as retail deliveries.

The patterns of coal usage, competition, and transportation charges vary among coal-producing areas and tend to create a geographic marketing pattern. Thus, coal produced in Pennsylvania, Maryland, and northern West Virginia is marketed primarily in the northeastern part of the United States (New England and Middle Atlantic States, including Maryland and the District of Columbia), whereas coal produced in southern West Virginia, Virginia, and Kentucky is marketed to a large extent in the Midwest, in the area around the Great Lakes, and to tidewater for export.

Figure 66 shows the amount of coal sold to electric utilities and the percent of the total utility shipments, by regions, for 1957 and 1960. The year 1957 was selected for comparison because that is the beginning of the statistical series applicable to this chapter and amenable to the regional breakdown we are using. The figures for regions V to IX are grouped in one total. Figure 67 shows the distribution of coal sold through retail dealers, figure 68 the coal sold to coke and gasmaking plants (only a few gas plants are still operating), and figure 69 to "all others," which category includes mainly industrial users.

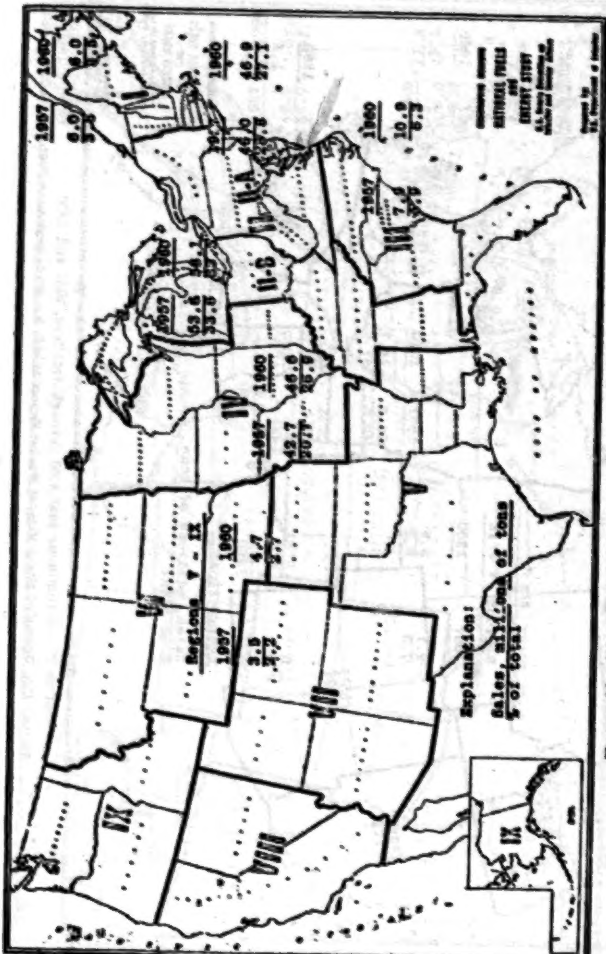


FIGURE 65.—Bituminous coal sold to electric utilities, 1957 and 1960.

Source: U.S. Bureau of Mines Mineral Market Report M.M.S. No. 3303, September 1961.

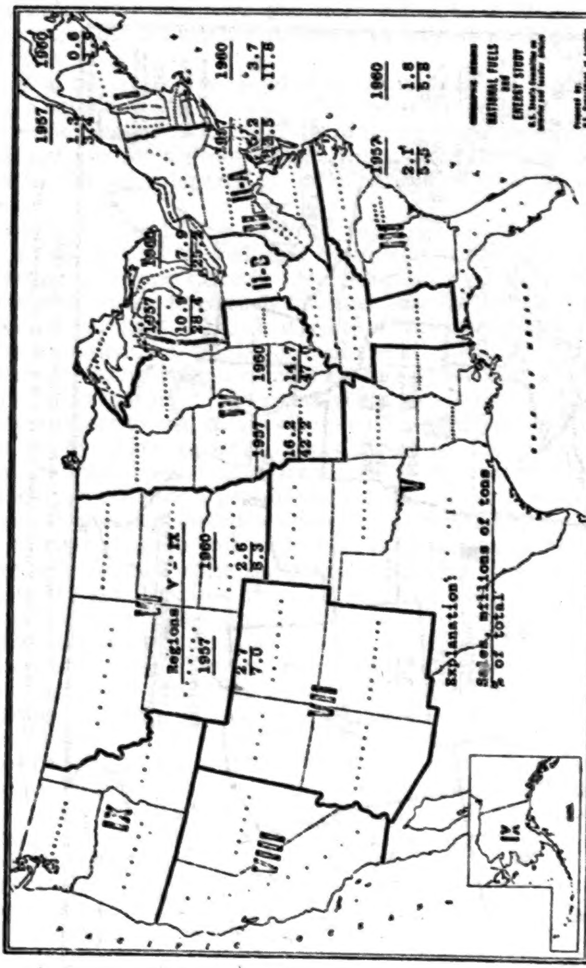


FIGURE 67.—Bituminous coal sold through retailers, 1957 and 1960.

Source: U.S. Bureau of Mines Mineral Market Report M.M.S. No. 3302, September 1961.

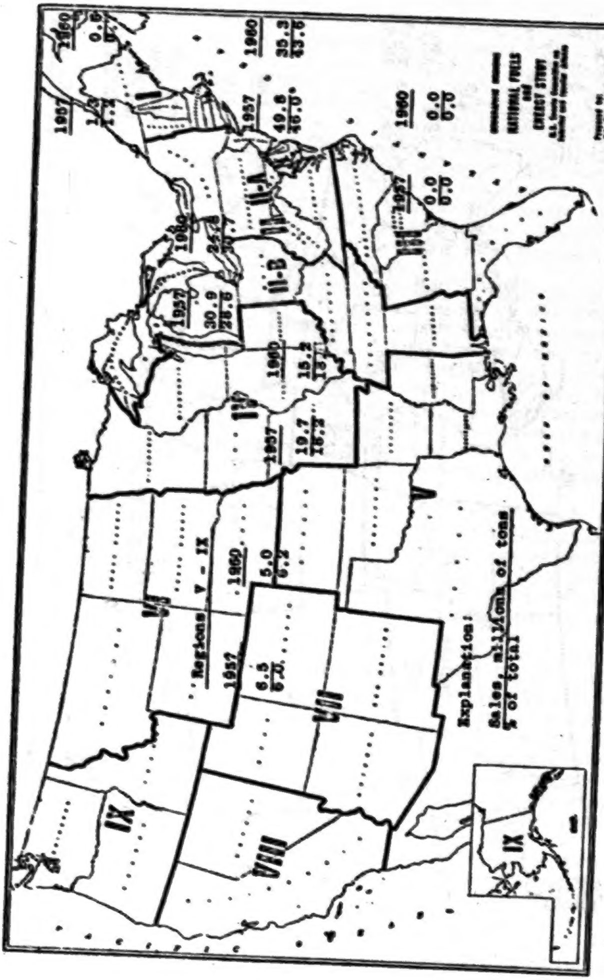


FIGURE 68.—Bituminous coal sold to coke and gas plants, 1957 and 1960.
Source: U.S. Bureau of Mines Mineral Market Report M.M.S. No. 3302, September 1961.

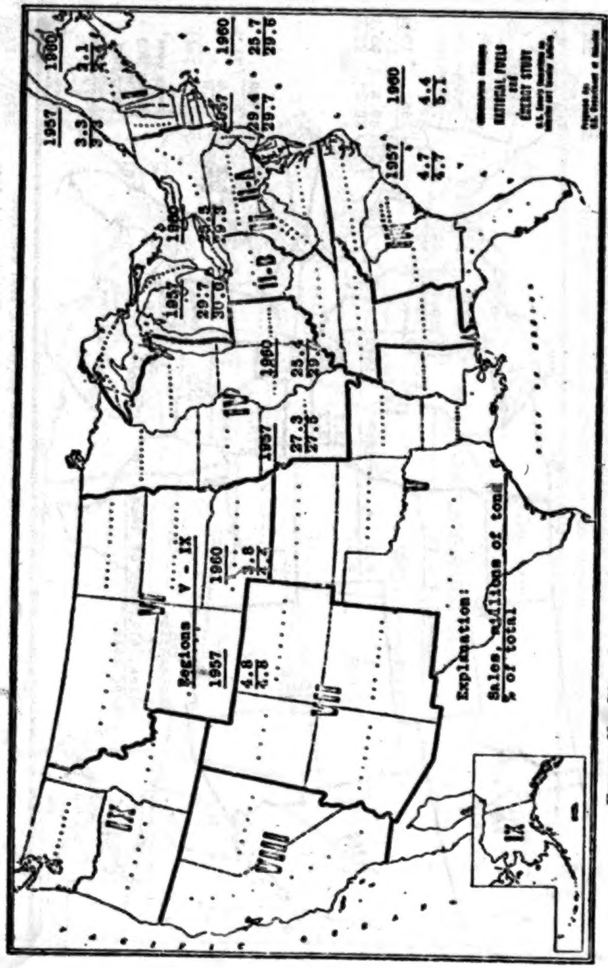


FIGURE 69.—Bituminous coal sold to "Miscellaneous users" in 1957 and 1960.
Source: U.S. Bureau of Mines Mineral Market Report M.M.S. No. 3302, September 1961.

Pricing

Originally all coal was sold as it came out of the mine and was called run-of-mine coal. The primary use was for heating purposes. Customer dissatisfaction with the fine or slack coal and with the fragments of rock and other impurities contained in the run-of-mine product led to the first crude forms of preparation, such as picking out the fragments of rock by hand and sizing by use of makeshift screens. The fine coal passing through the screens was usually poorer in quality than the run-of-mine and larger sizes of coal, and there was a limited demand for it. As a result, the larger or prepared sizes were priced higher than run-of-mine coal while the fine sizes were priced lower, in order to maintain an average realization as nearly equal as possible to the run-of-mine price. The introduction of costly preparation facilities at the mine led to an even greater number of size designations, each carrying a different price.

The larger sizes were sold in substantially smaller tonnages than slack sizes, with the result that the cost of marketing was considerably higher. This made it necessary to widen further the price spread between the larger sizes, such as lump and egg coal, and the finer sizes of slack. As the market for larger sizes of bituminous coal declined—railroads, home heating, and some industrial plants—many mines serving this market had to crush their coal to the smaller sizes needed by the utility and general industrial markets. A substantial part of this market was demanding more precise sizing and cleaning, and all told there may have been hundreds of combinations of sizes and qualities.

Logically there could have been a substantial increase in the price of coal to utility and general industrial markets—which by then had developed into the industry's principal source of revenue—but this was impossible because of the competition developing from residual oil, natural gas, and hydropower. Thus the price pattern that had developed under one set of market conditions persisted even after those conditions had changed.

A special pricing situation developed in connection with coal for metallurgical use. The steel industry requires coals of special quality for the production of coke. As the steel industry grew, this requirement led to the opening of mines to produce coal for that particular use. High-quality coking coal commands a higher price than other coal of equivalent sizing. But steel is a cyclical industry, and in order to keep the mines in operation and to minimize losses during periods of low steel production, the coking-quality coal is sometimes directed into the general industrial market where it must meet the price of the coal normally servicing that market.

Some mines are opened and equipped for the specific purpose of supplying electric generating plants. Many of these electric plants are willing to take run-of-mine coal, doing their own crushing. The avoidance of preparation at the mine makes it possible to quote lower prices to the utility companies able to use coal in this manner. This practice, in turn, has forced mines having elaborate preparation capacity, that was developed under different marketing conditions, to reduce their prices in order to meet the competition.

Coal is sold by three basic methods: Spot orders, annual contracts, and long-term contracts. Spot orders usually specify delivery within

30 days, although occasionally the time is extended. Annual contracts, as the term implies, provide for the delivery of coal over a period of 12 months; while usually for specific tonnages, occasionally they specify maximum and minimum allowances. Long-term contracts are generally written for periods of 5 or 10 years, although some run as long as 20 years. They often call for the entire output of a mine. No information is available on the tonnage of coal sold under contracts of various duration.

Contracts allow the mine operator to receive a stated price for his production and may allow him to benefit from increased production efficiency during the term of the contract. Long-term contracts normally have escalation clauses, usually quite elaborate, that provide for price adjustments as a result of increased labor and supply costs. They also have cancellation clauses.

Regardless of price or of the way the coal is sold, the price to the consumer or retailer is usually f.o.b. the mine. Exceptions to this general rule are when coal is sold to commercial dock operators on the Great Lakes or at tidewater for export. The price f.o.b. mine for a particular class of coal is not, however, always the same, adjustments sometimes being made to offset freight charges in some degree in order to meet competition.

An appreciable amount is sold on the basis of B.t.u.'s delivered to the purchaser's plant. Government purchases generally embody penalty clauses by which the supplier receives less per ton for his coal if the B.t.u. value or other quality drops below that guaranteed in the bid; Tennessee Valley Authority contracts include both premium and penalty clauses, as do also some commercial contracts.

The bituminous coal industry does not post formal price quotations. The Bureau of Mines publishes statistics on average price of coal sold, f.o.b. mine, making a distinction between coal sold in the "open market" and coal "not sold in open market." The latter category refers to production by mines owned by or affiliated with the consumers. The Bureau of Labor Statistics publishes figures on wholesale prices. The figures published by the Federal Power Commission are delivered prices to steam electric plants, reflecting, therefore, from year to year not only changes in the f.o.b. mine prices but also changes in the source of supply, method of transportation, and freight rates.

CRUDE OIL

As described for coal, the marketing of which begins with the mining operation itself, the marketing of crude oil spans the entire territory from the wellhead to the refinery.

The movement from field to refinery is discussed in detail in the chapter on transportation, but a few features that affect marketing practice are repeated here. The large trunk pipelines for the most part are owned by the large integrated companies and are common carriers subject to regulation by the ICC. The gathering lines that connect individual producing leases to the trunklines also are owned generally by the pipeline companies, but some are owned by the producers themselves. When a well is brought into production, its operator understandably seeks to market the oil by selling it to someone who can provide a pipeline connection.

PART IV—INTERFUEL COMPETITION

Introduction

Competition among fuels is a complex of economic, technologic, and political forces. The three fuels—coal, oil, and gas—compete with one another for the electric energy, space heating, and process-heat markets; electric energy (including hydropower) then competes with coal, oil, and gas for parts of these same markets. The subject is complex technologically because of the many areas in which it operates, as described in the chapter on technology: production, conversion of the raw fuels to energy, transportation, and use. As technology changes, so do costs and competitive relationships. The joint technologic-economic complexity is compounded by atomic energy. The subject is politically complex because it is involved with problems of trade, utility and transportation regulation, conservation, public versus private power, and such social problems as unemployment and public fears regarding disposal of atomic wastes.

The present chapter attempts to untangle some of this complexity. As indicated in a preceding chapter (Part I: Energy in the Economy), part of the market held by each of the fuels is noncompetitive with other fuels. The following pages deal only with the interfuel competitive aspects.

Historical Perspective

Prior to the Civil War, wood was the dominant fuel in this country, both for home heating and as industrial fuel; more than half of all iron produced, for example, was smelted with charcoal. (See figs. 1 and 90.)

When coal began to displace wood, it did so as a unique energy source that provided services wood could not. Its flame was found to be more adaptable and controllable; its energy was found to be more concentrated, so that it was more easily and cheaply transported; it could be handled more readily than wood logs or charcoal; and it was available in quantities that wood could never achieve. It invited new and expanded uses. Between 1850 and 1890, consumption roughly doubled every decade, largely the result of increasing use as a metallurgical and locomotive fuel. Then after 1900 came the rapid growth of the electric power industry. None of these markets could have developed with wood. Coal dominates the electric generating market to this day.

Coal reached the peak of its growing share of the energy market in 1910, having yielded to a new fuel—oil—unique and necessary to the time in the same way that wood did when it yielded to coal. Oil initially had a small use for illumination, but after 1900 it began to be used more and more by railroads and naval vessels. Just as coal had formed a long-lasting union with electric generation, oil formed a long-lasting union with transportation. The demand for motor

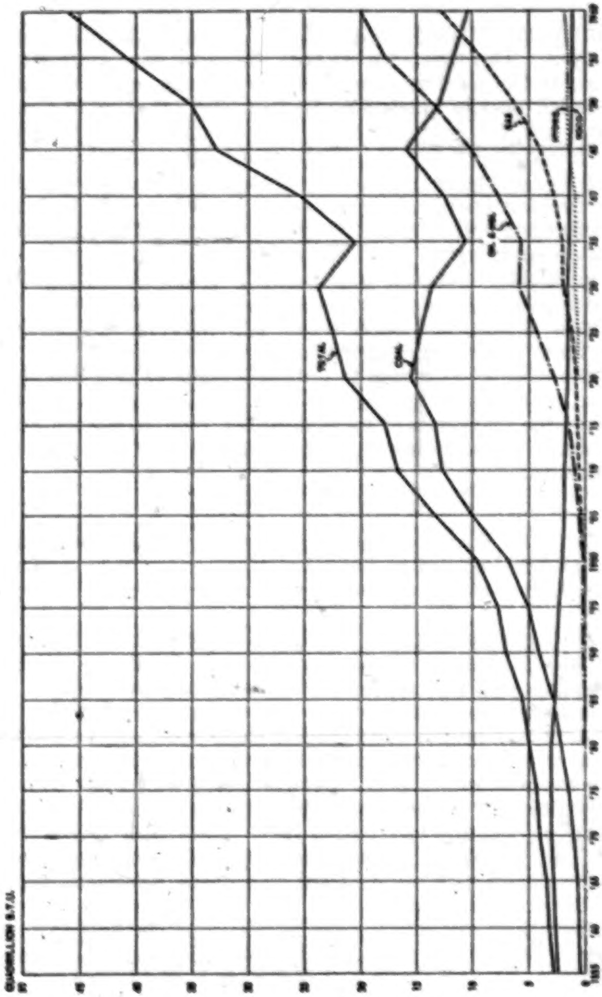


FIGURE 90.—Trends of competitive consumption of primary energy in the United States.

Source: 1855–1955 after Schurr and Netschert, "Energy in the American Economy, 1850–1975," pp. 511–513; 1960 Bureau of Mines final summary.

fuels increased sixfold in the period from 1925 to 1955. Concurrently, oil was invading other coal markets as well, and by 1940 had preempted a great deal of the home heating market. The net result has been a decline in coal consumption that, except for an interruption during World War II, has persisted to the present. The two peak periods, 1918 and 1943-44, were war years.

Oil in its turn—and coal, too—has had to face up to gas, as unique with respect to oil and coal as oil was with respect to coal, and coal to wood. Gas became competitively active on a national scale as soon as there was developed a technology of constructing high-pressure, long-distance pipelines to carry it to a waiting market. In 1945 only about 1 trillion cubic feet of natural gas entered interstate commerce. By the mid-1950's, this volume had increased fivefold; by 1960, eightfold. Gas displaced coal in a number of industrial uses, and coal and oil in space heating—a market that had been previously claimed by wood, coal, and oil in turn. The movement of gas into this market has been one of the major factors slowing the growth of oil consumption.

Table 1 in part I suggests the end-use patterns presently in existence. The table shows the pattern in detail as it was in 1955, which is the latest year for which this breakdown has been published, together with the totals for 1961. The cycle is not ended, for electricity is making inroads into the gas-residential market.

Influencing Factors

Competition among products serving a common market can be defined as the pattern of effort among the producers of those products to secure the favor of the customer by offering to meet his wants on the most favorable terms. The quantities used represent the result of those efforts. In other words, competition results from the ability and willingness of the customer to shift from one product or supplier to another. When, in an economic sense, consumers of fuel are able to shift freely from one fuel to another, there is intense competition among the fuels, and the degree of competition intensifies and softens as this freedom of choice expands or contracts.

Many factors influence this freedom of choice. In part of the energy market, the consumer has equipment that enables him to switch at will from one fuel—coal, oil, or gas—to another; freedom of choice is wide, and competition is keen. In other parts of the market, more than one of the fuels could serve the purpose, but some added investment in the way of new equipment may be needed; the economic choice is less free and competition accordingly less keen. In still other parts of the market, one fuel may satisfy the consumer's wants in a way that no other fuel can, in which case he really has no practical choice, except as to which supplier he selects.

Where more than one fuel may be used, the choice is approached initially on the basis of cost. Other factors are convenience and simple preference, and particularly reliability of supply. However cheap a fuel may be, it may not be selected if the user cannot be certain, within the dictates of his needs, that he can get it in any quantity he wants whenever he wants it and at a price he can afford. There are also political factors, which may circumscribe all the others and that operate in a manner not always immediately obvious. At any partic-

ular time, Congress or other authorized public institution may determine that the public welfare requires some interference with market economics, in which case a whole chain of consequences may ensue.

The situation at any given time represents an economic equilibrium, but the equilibrium is both fragile and fleeting.

Each of the several factors is discussed under appropriate headings in the following pages, to the degree necessary to open the way to a discussion of competition in the individual market areas. Many are intimately related, and the limits of discussion are in a sense arbitrary. The point of much that is said has already been made and documented explicitly in earlier chapters.

THE PHYSICAL CHARACTER OF FUELS

The historical development of the use of fuels is based in good part on their physical character. As already noted, one reason coal replaced wood is because the energy in it is more physically concentrated; as a result, the flame is more controllable, and small hunks of this concentrated energy can be handled more easily than one can handle logs of more dilute energy.

The solid nature of coal has influenced not only its competitive strength in early years but also its competitive weakness of later years. When coal is mined, it must be broken away from its native confinement. The pieces must be physically loaded and then (although some coal gets burned in the form in which it leaves the mine) moved out of the mine to a cleaning plant, dumped, ground into smaller pieces, separated from the processing water and again picked up and loaded for transporting. It should not be inferred that these are separate steps. They are not; in modern operation the sequence is continuous and automatic, but it does call for equipment, labor, and expense all related to the fact that coal is solid. At the destination, the coal must be unloaded again and then moved through another series of steps, all required because of the solid nature of coal, before it reaches the burning device. When it burns it produces an ash that must be removed. The mechanics of producing, delivering, and using a liquid or gas are much simpler, although, to be sure, the liquid and gaseous fuels go through their own processing steps before they are usable.

The rental or availability of storage space and railroad spurs in cities where real estate values are high may be an appreciable factor in the consumer's decision on what fuel to use.

The softness of bituminous coal causes it to abrade and to form dust. The dust is dirty, and this militates against its use in the space-heating market. This, of course, is not true of anthracite.

Architects and consulting engineers prefer the simpler design and fewer potential difficulties associated with the use of liquid or gaseous fuel. The continuing attempts to liquefy or gasify coal, going back many years, and the present development of the coal pipeline, are attempts to overcome the disadvantage of the solid state.

At the same time, the solid state has an advantage in some uses. Coke not only supplies heat in smelting processes, but physically supports the ore mass.

As to oil, its liquidity has constituted its most distinct advantage. Small compact engines have been built around this trait and are now

thoroughly established as an almost unchanging part of present-day technology. Nearly a fifth of all the energy consumed is used to run motor vehicles, diesel locomotives, and aircraft. If coal can be made effectively "liquid" so that it can be used in turbines, it may recapture part of this market.

Yet, because it is a liquid, oil has a disadvantage with respect to gas. With gas, the user need only turn a valve, whereas to use oil he may have to provide storage space and tanks, and unloading docks or access roads and truck turnaround space. He may have to go to the added effort and expense of installing equipment to control air pollution. Oil, being a liquid, has dissolved in it constituents that sometimes foul equipment and leave a greasy soot that many homeowners dislike.

The heat of gas—and of electricity—can be distributed evenly more readily than can the heat of coal or oil, and the heat level can be maintained indefinitely. Gas flame can be pinpointed in a way that no other fuel permits. Still, the physical nature of gas is not all advantage. Explosions do occur, as indeed they do with oil. Because gas *is* a gas, it must be transported by pipeline, and it cannot go to market unless a pipeline will take it there, not only physically but economically. Oil, on the contrary, can choose a pipeline, barge, tank car, or truck as fits a specific competitive situation. It is this transportation feature regarding gas that has engendered the effort to liquefy it.

SUPPLY

The cost of energy starts with the cost of the primary material. To now, there has been no lack of coal, oil, and gas in the ground that would exert an upward pressure on price. As implied in the chapter on the comparison between requirements and supply, this promises to continue to be true. In terms of dollars having a constant value, the cost of finding, developing, and producing oil and gas jointly appears to some observers to have been fairly constant and on average could well remain so for some time; the great coal resources of the country make this even more probable for coal.

Another element of supply as it affects competition is assurance of delivery. International crises have sometimes caused oil shortages in particular markets, and this is sure to happen again some time or other. Work stoppages in the bituminous coal industry have caused disruption in delivery, but there has not been an industrywide strike in the coal industry in over 12 years, and railroad strikes also are much less a matter of concern than formerly.

PRICE

A distinction must be made between the delivered price of a fuel and the price at the pithead or wellhead. Both are quoted in economic discussions of fuel competition. It is not always easy to remember that a fluctuating transportation cost must be added to the field price and that sometimes this is greater than the cost of the fuel itself.

Delivered price is normally both an ambiguous figure and an incomplete one. It is ambiguous because it is quoted in terms of the natural unit—ton, gallon, or cubic feet—whereas it is not the natural product burned that is significant but the energy the product provides. It takes 4⅙ barrels of heavy oil or about 25 M c.f. of gas to provide the same amount of energy as a ton of coal.

The delivered price of a fuel is an incomplete figure because to it must be added the cost of equipment and labor needed to use it. Whereas to use gas one need only install an appropriate burner and turn a valve, to burn oil or coal he must provide a variety of other equipment and services. Both delivered price and utilization cost are taken into account when a consumer makes his choice of fuel. In some cases, the differences between the fuel cost and the "cost as consumed" may be quite large. For example, the estimated cost of a 10,000-pounds-per-hour boiler unit, installed, is about $16,000 for gas and $35,000 for coal. The coal unit costs the more because it requires equipment—such as a stoker, storage bins, and ash-removal facilities—that the gas unit does not and because of higher installation costs. As a result, gas can be dearer than coal in terms of delivered B.t.u.'s, yet the lower capital charges can make gas the more economic overall. On the other hand, the aggregate saving in the cost of coal at the plant gate over a period of years may more than offset the higher capital costs. In larger boiler units, in those areas of the country where coal is economic, this is usually the case.

TRANSPORTATION

Geography initially establishes the general patterns of fuel consumption and is responsible for the location of many fuel-consuming industries. The reason is the absence of a transportation cost. The coke-oriented steel industry, for example, had its origin near the coalfields of the Appalachians; few, if any, significant carbon black plants operate outside of the oil and gas fields of the Southwest. Generally every fuel is cheaper at its point of production—at the wellhead or mine mouth—than is another fuel that must be transported to that same location. Gas originating in the Southwest is transported through pipelines that traverse near the coalfields, yet in West Virginia, Ohio, and other eastern coal States virtually all the electric utilities use coal. Then, as these fuels move toward more distant markets, the relatively higher unit transportation costs for coal dispel some of this locational advantage.

This element, transportation, is what makes interfuel competition so severe in those areas having little or no native energy resources, such as along the Atlantic seaboard, particularly in New England. In order to compete, the several fuels must be priced approximately the same on a B.t.u. basis as delivered, particularly in industrial markets. Even for space heating, the preference premium paid for gas cannot get too high.

Transporting coal always comes high, constituting on average throughout the United States more than four-tenths of the delivered price of bituminous. From a given region of production, the delivered price of coal is directly related to the distance traveled.

The cost of moving oil is low or high depending on how the movement is made. Heavy fuel oil or crude oil can be shipped from the gulf coast or from the Caribbean to the east coast cheaply, but from there it moves by rail, barge, or truck at costs that are roughly comparable to the cost of moving coal. The low cost of marine transportation is one of oil's major competitive strengths, especially in those locations that can be supplied directly from the tanker. The pipeline transportation of gas is substantially less than the cost of moving

coal or oil by rail, but higher than the cost of moving oil (or coal) by ocean transport.

TABLE 40.—*Prices at point of production*

	Oil—Bunker C—Posted prices [1]				Natural gas [2]		Bituminous coal, dollars per ton [2]
	At gulf coast		At Aruba				
	Dollars per barrel	Dollars per ton, coal equivalent	Dollars per barrel	Dollars per ton, coal equivalent	Cents per thousand cubic feet	Dollars per ton, coal equivalent	
1946	1.35	6.07			5.3	1.34	3.44
1947	1.69	7.03			6.0	1.52	4.16
1948	2.43	10.10			6.5	1.65	4.99
1949	1.43	5.95			6.3	1.60	4.88
1950	1.68	6.99			6.5	1.65	4.84
1951	1.75	7.28			7.3	1.85	4.92
1952	1.64	6.82			7.8	1.98	4.90
1953	1.70	7.07			9.2	2.32	4.92
1954	1.85	7.60			10.1	2.45	4.52
1955	2.00	8.32			10.4	2.52	4.50
1956	2.14	8.90	[3] 2.40	9.97	10.8	2.62	4.82
1957	2.65	11.02	2.56	10.62	11.3	2.74	5.08
1958	2.20	9.15	2.18	9.05	11.9	2.89	4.86
1959	2.00	8.32	2.00	8.32	12.9	3.15	4.77
1960	2.47	9.02	2.00	8.32	14.0	3.30	4.69

[1] Platt's Oil Price Handbook.
[2] Bureau of Mines.
[3] Dec. 31, 1956.

Table 40 shows the postwar pattern of prices, at points of production, upon which U.S. transportation charges are mounted. The prices shown for heavy fuel oil are posted prices, but for the gulf coast these are representative of actual sales price. (Posted prices for gulf coast bunker C oil are not usually subject to discount.) Caribbean fuel oil is subject to discount, however, by unknown amounts, so that sales price is cheaper than posted price. According to the table, the price of heavy fuel oil at the point of production, and as measured by its heat content, has been nearly twice the price of coal at the mine since about 1956, while the price of gas has been substantially less than the price of coal. (New contract prices for gas sold to pipelines have been going up, and the contract prices now being negotiated make the price of gas equivalent to that of coal at $4.37 a ton, or substantially the same for the two.) The fact that coal has difficulty competing with oil in markets near the ports of entry is a measure of the high transportation cost that coal bears.

With its relatively high cost in eastern harbors and high overland transportation charges, the market for heavy fuel oil is confined to a strip bordering the waterways, about 125 miles inland from the coast and 20 miles each side of the major riverways. Each mile overland adds more to its delivered price while reducing the delivered price for coal at the same location. The point is soon reached where it is uneconomic to move residual oil farther inland, and coal and gas then compete for the market under similar considerations.

Gas has much farther to go, generally, than coal, and its initial large price advantage over oil and lesser advantage over coal are ultimately overcome, despite its low transportation cost. The States of Vermont and Maine use no natural gas for this reason.

In concept, there is a degree of similarity in the pricing of transportation services for all three fuels. The sale of interruptible gas represents an adjustment in transportation charges, and so is analogous, in this sense, to the reductions in rail rates covering the movement of coal to New York Harbor and of residual fuel oil into New Hampshire in order to sustain competition. (See Part VII: Policies, Laws, and Regulations.)

JOINT PRODUCT CONSIDERATIONS

All three of the major fuels are produced or transported as though they were jointly produced or transported with other products. Electricity, too, is sometimes a joint product. This factor has an impact on pricing and competition.

Coal mining yields several products in the form of different sizes, and aside from what is deliberately produced some fine coal is unavoidably produced in coal-cutting operations. Coals of special quality also are produced for specific markets. In some mines the successful extraction of metallurgical coal requires the mining of a certain proportion of steam coal as well, and in many instances availability of metallurgical coal therefore is directly related to the market for steam coal; in other cases the reverse is true. In the opposite direction lack of demand from the steel industry can and does send metallurgical coal into the steam market.

Oil and gas are produced jointly, of course, and both are frequently produced from the same well. The proportions differ. The industry can shift its efforts somewhat between the two, but it can never be sure whether successful exploration will result in oil or gas.

Heavy fuel oil is a byproduct of refining in the United States. As with byproducts generally, the minimum price required in its sale is an amount large enough to balance out-of-pocket transportation and production costs. However, the lower the price, the more the incentive to install equipment to convert it into other and more valuable products. This is happening now, the yield of heavy fuel oil having been declining markedly in the United States for well over a decade. On the other hand, heavy fuel oil of foreign origin is not a byproduct, nor is it priced as one. It is a prime product at all Western Hemisphere refineries outside the United States and Canada and accounts for the bulk of their total output.

The electricity generated at Government-sponsored power facilities is frequently a byproduct. Power from the St. Lawrence Seaway is a byproduct, so to speak, of the principal objective to improve transportation, and in Western States it is a byproduct of an irrigation objective, along with conservation and recreation. This byproduct is marketed in direct competition with the fuels. Similarly, electric generation related to the atomic energy and nuclear power programs also may be called a byproduct.

Transportation, too, has its joint-product aspects. Transportation of coal is a joint service with transportation of other bulk commodities and competes with them with respect to rates and for rolling stock. There is also an analogy in marine transportation, in that tankers that would otherwise be idle are sometimes used in transporting grain. Natural gas pipelines sometimes find that they have idle capacity in

offpeak periods, which idle capacity, in the sense that it is unavoidably created as a result of supplying another market, can be called byproduct; as is normal in byproduct economics, the item is sold if a market exists and if it is economically feasible to do so.

TECHNOLOGY

The effect of the technology of exploration, production, and transportation on competition gets incorporated in the cost and price of the product, which have been discussed above and need no further reference here except to draw attention to the record of the coal industry. Even though wage rates and the cost of materials and mining machinery increased an average of 70 percent during the decade 1950–60, the average price of coal f.o.b. the mine has managed to stay firm as a result of the cost-controlling effect of mechanization.

Of more immediate relevance to competition is the technology of use, which has acted particularly to the detriment of coal. Annual retail deliveries of coal (mainly for space heating) declined by about 55 million tons from 1950 to 1960 with the switch to oil and gas, and railroad use of coal dropped 60 million tons in the same period as the railroads converted from steam to diesel engines. Thus these two factors alone reduced coal consumption by about 115 million tons a year, or nearly 80 percent of the total decline in the nonutility areas of consumption. Conversion of ship use from coal to heavy fuel oil and improvements in iron smelting claimed an additional 25 million tons of annual output.

Another technologic development has been the progressive improvement is what is called heat rate, by which is meant the weight of coal (or B.t.u. content) used in an electric generating plant to produce 1 kilowatt-hour of electricity. This is described in detail in the chapter on the technology of electric generation. As recently as 1950 the heat rate averaged about 1.2 pounds of coal per kilowatt-hour; in 1960 it averaged less than nine-tenths of a pound. This reduction over the past 10 years alone "cost" coal some 60 million tons a year at present rates of electric generation. Generation of electricity from oil and gas has experienced similar but less striking improvements in efficiency.

Another facet of technology and its impact on fuel competition relates to small boilers, those that serve the general industrial market as opposed to the electric utility market. The major change in industrial energy utilization has been the trend toward what are called package boilers, by which is meant boilers assembled at the factory and shipped as one piece, with consequent savings in cost, particularly of installation. The package boiler is much more adaptable to oil or gas firing than to coal firing, and can be designed for much higher capacities per dollar of cost or unit of size.

Still another area of technologic change is now beginning to erode the coal market. Until about 3 years ago the metallurgical fuel market was considered captive to the coal industry. During the past 50 years coke accounted for nearly all the fuel used in blast furnaces, but now oil or gas can be injected with the air blast, reducing the amount of coke needed. Coal technologists are moving to combat this by injecting coal with the airblast.

GOVERNMENT POLICY

Government policy has such pervasive influence that a special part of this report is devoted to it. It relates to competition in many ways: Through its impact on supply, ranging from limitations on production (oil and anthracite) to controls of imports (oil) and control over construction of facilities (gas and electricity); through direct competition between Government and industry in electric power; in its impact on prices and costs, both indirectly through import duties and other taxes and directly through control over sales contracts, utility ratemaking, and cost of transportation; and in control of the end use of the fuels, i.e., "inferior use" of gas (the *Transco* case) and air pollution. (See part VII.)

A point not previously discussed in detail is that different jurisdictions of Government sometimes pull in directions that have opposite effects. Several different agencies regulate, control, or otherwise influence competition among the fuels, and each tends to act independently of the others within its own interpretation of its charter. We have made no attempt to itemize such occurrences, but the following instance has been brought to our attention. While the Department of the Interior maintains quotas against the import of foreign oil in order to help sustain the American industry, the maritime laws of the United States (through the requirement that coastal movement of oil be in relatively high-cost U.S.-flag tankers) operate in the opposite direction by giving foreign oil and oil products a price advantage over domestic fuel.

There are other instances, of course, in which Government policy pulls in only one direction. For example, Government is a large consumer of fuel, and its procurement practices therefore exert important competitive pressures. A specific example in this regard is the Tennessee Valley Authority, the largest single purchaser and consumer of coal in the United States. In 1960 it purchased about 19 million tons of coal (to the exclusion of other fuels), mostly from mines that sell also to public utilities. Of this amount, 1,800,000 tons consisted of spot purchases each under $10,000, at prices generally lower than paid on term contracts and in some instances from the same supplier. Spokesmen for the coal industry say that the result of TVA purchases is a pressure on the producers to charge other utilities the same low price they charge the Tennessee Valley Authority. In making contracts the TVA can take advantage of special rates applicable to transportation of Government property. Another illustration is the setting aside, in Government purchase contracts, of certain portions of Government fuel procurement to be met by small producers.

Two final points may be made:

Hydropower produced by public projects, both Federal and State, is sold to electric utilities sometimes in competition with fossil fuels. A case in point is the operation of the Power Authority of the State of New York, which has arranged to sell much of the electric energy from Niagara Falls and the St. Lawrence project to utilities in the State. Blocs of power have been sold to the Niagara Mohawk Power Co., Rochester Gas & Electric Co., and New York State Electric & Gas Co. These companies operate a number of large coal-burning

generating stations. Through the distribution facilities of these three utilities, the power authority has arranged also to distribute electricity to other companies beyond the State. Between 1958 and 1961 the Niagara Mohawk Co. decreased its coal usage from 3.2 million tons to 2.5 million tons while during the same period increasing its purchases of hydropower in coal equivalent to 3.3 million tons.

Much public regulation initially had no intention of influencing competition among fuels. The legislation was for the purpose of protecting the American consumer in his direct relation with a particular producer or was related to some other aspect of national interest. Some Government actions thus now find themselves in an environment for which they were not designed and on which they therefore have an influence not foreseen. For example, the commodity clause of the Interstate Commerce Act (1906) prohibits railroads from owning properties that produce the freight the railroads haul. A second clause exempts bulk transportation by water carriers from regulation. At that time coal was the principal fuel, and the railroads the principal carriers, and their competitive position was not affected. Now there are three basic fuels and additional methods of transportation, and the competition is keen.

REGIONAL FACTORS

Aside from the circumstance that fuels are most widely consumed near their points of production, fuel consumption reflects also regional shifts in industrial concentration. The migration of the New England textile industry to the South, for example, added to one region's fuel consumption while subtracting from another's. When such shifts occur between one native energy region and another, one fuel may be substituted for another. There is no information, however, on how much this amounts to except in an illustrative way here and there. According to the latest Census of Manufacturers, iron foundries in the coal-consuming regions of New York, New Jersey, Pennsylvania, Ohio, Illinois, and Michigan reported less activity for 1958 than for 1954, while foundries in the gas-using areas of California and Texas reported a substantial increase in activity.

An example of the regional factor is in the development of nuclear energy. By some happenstance, the first two commercial reactors—Shippingsport, Pa., and Dresden, Ill.—are in coal regions.

CONSUMER PREFERENCE

Consumer preference for a particular fuel is such a common phenomenon that little need be said about it here.

Despite the fact that natural gas and heating oil are more expensive than coal in some areas, they are preferred by householders to such an extent that they have taken over a large segment of the space-heating market. Gas is taking away markets from oil for the same reason—simple preference.

In the industrial market it is technically possible to conduct numerous operations with any fuel, but often the user prefers one over the other because it makes his task easier, although, to be sure, the choice is influenced also by technical considerations. As already indicated, the heat of gas and electricity can be distributed more readily than the heat of coal or oil, and the heat level can be maintained indefinitely.

Individual Markets

Residential and Commercial

In the postwar period the use of electricity in the residential market has grown at an average compound rate of 11 percent a year, gas at 10 percent, and petroleum at 7 percent, although the rates of growth have been much lower in the past 5 years. The use of coal has declined at a rate of 10 percent a year. In 1960 oil and gas each held about 40 percent of the market, and coal and electricity each about 10 percent.

The commercial market is primarily for heat and power—in hospitals, apartment houses, schools, and office buildings—and resembles the residential market. It is fairly small. In 1960 the market shares were gas 50 percent, oil 17 percent, coal 10 percent, and electricity 23 percent.

The top space in figure 91 shows the postwar changes in the deterioration of the retail coal market; retail deliveries (i.e., the residential, commercial, and some "offtrack" industrial markets) in 1960 totaled only 30 million tons or 67 million tons less than in 1947. Most of this decline was due to the switch to oil and gas for heating. The use of electricity for residential heating may enable coal to recapture some of this market.

Of the retail market remaining for bituminous coal about 60 percent is in the Midwest, primarily in Ohio, Indiana, Illinois, Michigan, and Minnesota. Most retail coal has been mined in the southern Appalachian area in the States of Virginia, West Virginia, and Kentucky. Even though the retail market declined nearly 20 percent between 1957 and 1960, these three States still supply about half of the retail market and any further loss would be taken mainly by them. The primary market for anthracite is Pennsylvania and in New England and adjacent States.

The price relations involved in the residential market are shown in figure 92, which shows indexes back to 1935 for added perspective. During this 25 years the average retail (delivered) prices of coal and oil have been consonant, indeed almost identical. The rapid rise in the price of each right after World War II was the result of the removal of price controls, and the rise ended as soon as they reached the competitive ceiling imposed by gas. Since that time the prices of the three have reflected their competitive interdependence. In 1948 and again in 1957 oil appears to have tried to push ahead, but each time was pulled back by the competition of the other two. As noted, the series shown for gas is for space heating only and does not reflect the average price paid by residential user for all gas. For example, from 1950 to 1960 the space-heating index rose by 44 percent. During that same period the average price for all residential gas as reported by the American Gas Association rose by 17 percent.

But these are national averages, whereas competition is more of a local problem. Figure 93 shows price relationships in Boston, a city for which there are data and that is in a hotly competitve area. Until 1953 the gas used in Boston was manufactured gas, made locally from coal and oil, and its price necessarily reflected the competitive

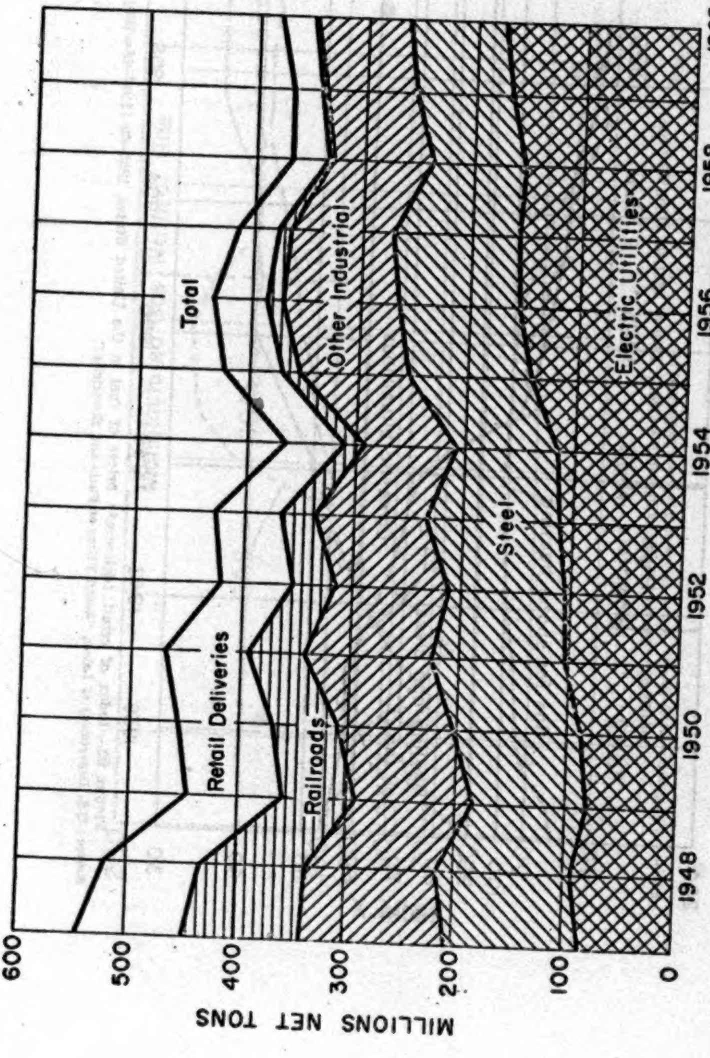


FIGURE 91.—Consumption of bituminous coal, by consumer class, 1947–60.
Source: U.S. Bureau of Mines (Minerals Yearbook).

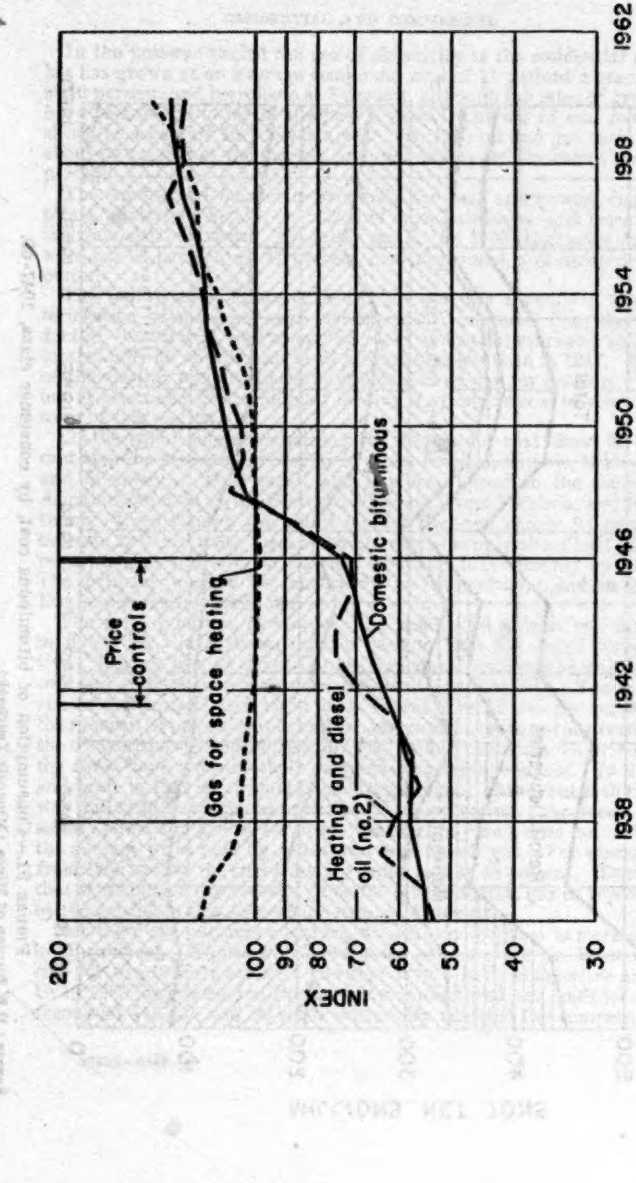


FIGURE 92.—Index of retail (delivered) prices of fuel in the United States, 1935–60 (1947–48=100).
Source: U.S. Department of Labor, "Retail Prices of Fuels and Electricity."

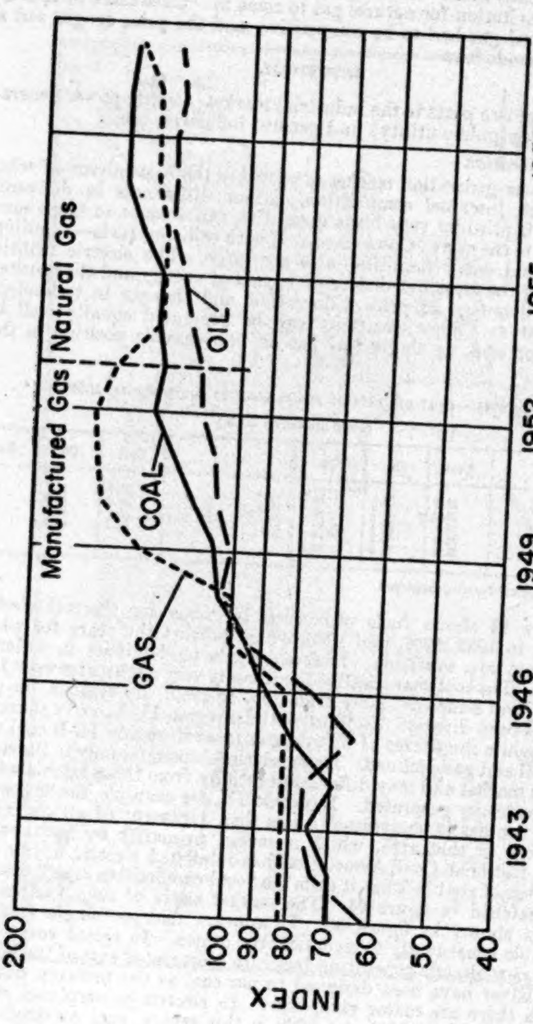


FIGURE 93.—Indexes of prices of heating fuel in Boston, 1941–60 (1947–49=100).

Source: U.S. Department of Labor, "Retail Prices of Fuels and Electricity."

prices of these fuels. As the price of manufactured gas rose, it provided an invitation for natural gas to come in. Once there in abundance, natural gas had to be competitive, and the price sought out a level that made it so.

INDUSTRIAL

There are two parts to the industrial market: electric power generation (mainly public utility) and general industrial use.

Power generation

A The power-generation market is probably the best mirror of what happens in interfuel competition. Minor differences in delivered price, multiplied by very large quantities, can amount to large sums of money to the user. Costs associated with utilizing fuels—handling, storage, and entry facilities—also are large. The electric utilities are among the most well-informed buyers of energy and the quickest to take advantage of price differentials and changes in technology of utilization. Since electricity can be generated equally well by gas, oil, or coal, no single fuel has an impregnable position in this market. B

TABLE 41.—*Cost of fuels at steam electric powerplants, 1952–60*

(Cents per million B.t.u.)

	Coal	Oil	Gas		Coal	Oil	Gas
1952	27.3	33.1	14.5	1957	27.5	44.4	19.5
1953	27.3	32.3	15.7	1958	27.4	39.6	20.7
1954	26.1	32.6	17.3	1959	26.5	35.2	22.3
1955	25.2	33.2	18.0	1960	26.0	34.5	23.6
1956	26.2	37.9	18.5				

Source: Federal Power Commission.

Figure 94 shows fuels utilization by areas for thermal electric utilities in 1952, 1957, and 1960, which bracket the years for which good data are available. Different fuels predominate in different regions. The coal share declined nationally very slightly between 1952 to 1960, and somewhat more from 1957 to 1960. By regions, the pattern has been diverse. To illustrate: In region II–A, coal's share declined while the shares of oil and gas rose; in region II–B coal rose while oil and gas declined. These relationships refer only to the steam electric market and may differ substantially from those calculated for total electricity generated. In region IX, for example, the 88 percent shown for gas is equivalent to less than 1 percent of all electricity generated in that area, which is served primarily by hydropower.

The National Coal Association has tabulated electric utility consumption of coal in what it calls the "coal-competitive area," the area cross-hatched in figure 94. The market share of each fuel in this area is shown in figure 95. It appears that no single fuel has been able consistently to undersell the others. In recent years, most of the new electric generating facilities constructed east of the Mississippi River have been designed to use coal as the primary fuel, although there are major exceptions. In electric powerplants placed in service between 1955 and 1960 in this region, coal constituted 94 percent of all fuel used in 1960; oil 2 percent, and gas 4 percent. The

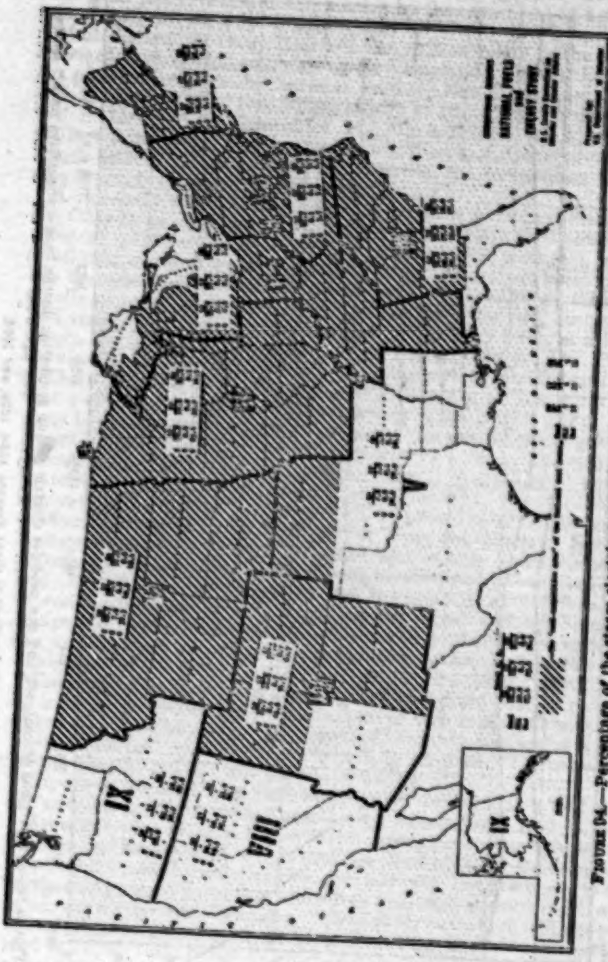


FIGURE 94.—Percentage of the steam electric generation market held by coal, oil, and gas, by regions.

Source: National Coal Association, "Steam Electric Plant Factors."

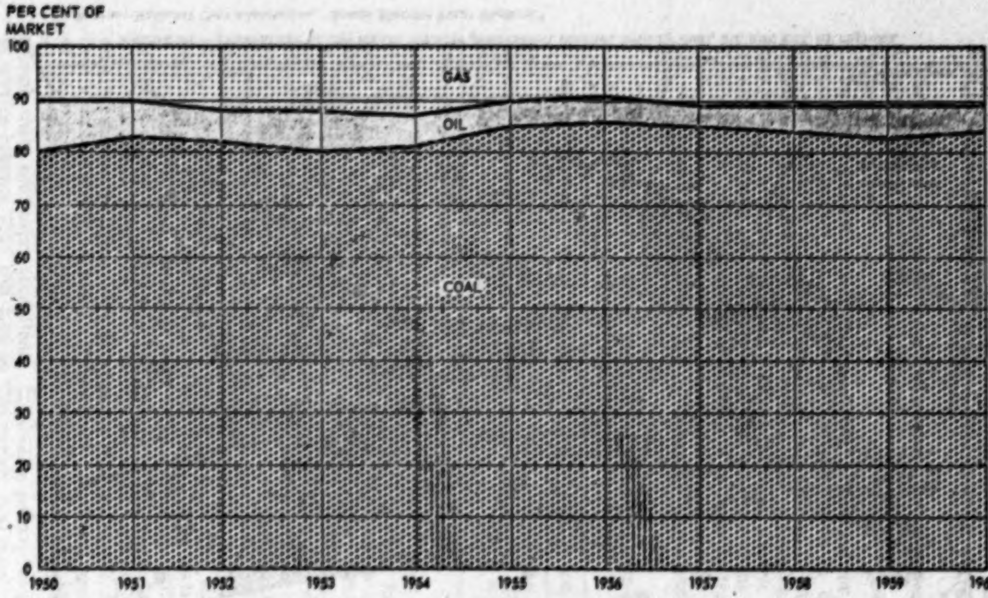


FIGURE 95.—Proportions of coal, oil, and gas used for electric power generation in the "coal-competitive area," defined by the National Coal Association. See figure 93.

Source: National Coal Association, Steam-Electric Plant Factors, 1958, 1959, and 1960.

combined market share of oil and gas in the coal competitive area in 1960 was equivalent to 33 million tons of coal out of a total market equivalent to 207 million tons. Since 1952 oil and gas have increased their joint participation in this market by the equivalent of 8 million tons of coal, coal itself by 70 million tons.

Most discussions about interfuel competition relate to the eastern seaboard, with special emphasis on New England. In New England, gas pipelines reach no farther than southern New Hampshire; Maine and Vermont have no natural-gas supply at all. Oil is the dominant fuel in Maine, New Hampshire, and Massachusetts (to where coal haulage is longest); coal is dominant in Vermont, Connecticut, and Rhode Island. With so little gas entering, the competition in this area is mainly between coal and residual fuel oil.

A relatively small amount of gas is used for power generation in the Ohio-Indiana-Illinois region as a result of the prime considerations of price and availability of underground storage. In the Southwest, on the other hand, almost all steam-generated electric power has been from gas, but here and there this is changing. The new Cholla plant of the Arizona Public Service Co. is designed for pulverized coal alone, and its Four Corners plant, being built, is a mine-mouth plant also designed for pulverized coal only. The Public Service Co. of New Mexico too is planning a mine-mouth plant.

The operations of the Consolidated Edison Co. of New York present a typical case history. This company is the largest utility company in the Metropolitan New York area. Its present steam-generating capacity is equivalent to 10.6 million tons a year. The company estimates that its fuel requirement in 1962 will be supplied 51 percent by coal, 25 percent by oil, and 24 percent by gas. In addition, the equivalent of 1 million tons of coal will be provided by the company's nuclear facilities and by hydropower from the Niagara Mohawk System. Also Consolidated Edison is constructing a new station at Ravenswood, Long Island, which will be equipped to burn only gas and oil. The company [1] reports that it expects to save $30 million in coal-burning equipment, cinder-catchers, coal and ash-handling equipment, water-frontage improvements, and other items realted to the use of coal. The planned energy consumption is the equivalent of about 1,500,000 tons of coal a year. On April 1, 1962, Consolidated Edison began to switch its East River plant from coal to residual oil in order to control air pollution, having been restricted in the use of gas (the *Transco* case). In early 1963, when the conversion is complete, 40 percent of boiler capacity will be oil fired. The converted boilers burned 450,000 tons of coal annually.

Figure 96 shows the prices (in cents per million B.t.u.) of coal, oil, and gas as reported by Consolidated Edison from 1950 to 1961.

An argument advanced by the coal industry regarding competition between residual oil and coal is that the effect upon the price of coal ripples out through the entire U.S. coal market. The producers in the northern Appalachian region who sell to east coast consumers sell also to consumers in other directions. These other customers will not pay more f.o.b. the mine than anyone else. Producers in other regions then tend to adjust their prices in order to hold their markets against the competition of the Appalachian producers, and so on market area by market area. For example, whenever a producer in Pennsylvania is

[1] Letters dated May 21 and June 26, 1962.

forced to cut his price on coal sold to customers in New York and Philadelphia, the same price concessions are demanded by customers in western New York, Ohio, Michigan, or Minnesota, and the concessions are quickly echoed in the coalfields of Ohio, Indiana, and Illinois.

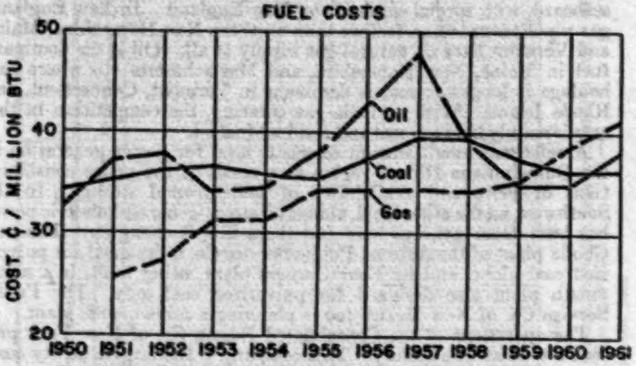


FIGURE 96.—Fuel prices paid by Consolidated Edison Co., 1950–60.

General industrial

General industrial fuels are used for process heat, boiler heat, or as raw materials.

The general industrial market has many of the aspects of power generation, with the major difference that the average industrial customer uses less fuel than the average powerplant, and that the capital charges are probably more prominent in relation to fuel costs. Also, these general industrial consumers are usually less able to achieve the efficiencies that power companies obtain with their larger boilers. For these reasons the general industrial market is probably not quite as sensitive to what it pays for fuel. Nevertheless, fuel costs together with consumer preference and tecanology have resulted in a significant decline in coal sales in the general industrial market in the postwar period, though not much of a decline has occurred since the mid-1950's. (See fig. 90.)

Because the data are so sketchy, it is not always possible to assign to competition a loss that one fuel may sustain at a given time, or that another may gain. One factor is the tendency in the industry toward purchasing power from electric utilities rather than generating one's own. In 1947, for example, industry generated about 30 percent of its electric power requirements, but less than 20 percent in 1960. There thus occurred a transfer of fuels from the industrial sector to the utility sector. This trend would be expected to be pronounced in the areas most heavily industrialized.

From 1954 to 1958—the latest 2 census years—coal's share of manufacturers' heat and power market (which excludes metallurgical coal and all raw material uses of the fuels) rose from 34 percent to 36 percent, oil's share rose from 11 percent to 16 percent, and that of gas declined from 56 to 48 percent. In the area east of the Mississippi

coal's share rose from 41 to 51 percent. In region IV oil's share rose from 10 to 15 percent, while in region IX it fell from 55 to 30 percent. Gas' share declined substantially in region II, but increased in region III. A different time span might show different relationships; both 1954 and 1958 were recession years, but no more satisfactory data are available.

With respect to the competitive prices involved, there is very little information. Data from the 1958 Census of Manufacturers show that in the manufacturers' heat and power market the delivered price of coal averaged 37 cents per million B.t.u. and that gas averaged 28 cents. East of the Mississippi both prices averaged about 37 cents. Available figures for oil apply to too great a variety of products to yield anything meaningful.

According to the American Gas Association, the average price of gas sold to industrial users rose by almost 60 percent from 1950 to 1960. With respect to interruptible sales alone, which is a point of common discussion, data for comparison are not available on prices of coal and oil that compete with this type of sale (about two-thirds of which is for boiler fuel, and one-third for process heat). However, in those regions where coal is a significant factor the average cost of coal to electric powerplants is below the equivalent average cost of interruptible gas.

Since 1949, residual fuel oil imported into the east coast has ranged between 17 million and 49 million tons of coal equivalent a year. This enters into both the general industrial and utility markets. Under the 1960 quota it was entering at an annual rate of 49 million tons of coal equivalent, of which 10 million tons was used in ships' bunkers in foreign trade and would not be supplied by domestic oil. If the importation were stopped, coal, natural gas, and domestic petroleum products would supply roughly an equivalent amount, in unknown proportions. Any additional coal produced would come largely from Pennsylvania, West Virginia, or Virginia, but its entry would be slow because many installations are equipped to burn only one fuel; the loss would be borne by the Netherlands West Indies and Venezuela. Any additional gas would probably come from Louisiana and Texas.

TRANSPORTATION

The table below gives the latest reliable data on the use of fuel in transportation. According to it, oil accounts for over 90 percent of the total. Figure 90 shows the rate at which coal has dropped out of this market, from 110 million tons in 1947 to 2 million in 1960.

Oil may not necessarily maintain its preeminent position in this market. The electrification of railroads and liquification of coal both provide potential threats.

TABLE 42.—*Fuels used in the transportation industry, 1955*

[Trillion B.t.u.]

	Direct	Via electricity	Total	Percent
Coal	333	54	387	4.8
Oil and NGL	7,430	5	7,435	91.9
Gas	254	12	266	3.3
Total	8,017	71	8,088	100.0

Source: Schurr and Netschert.

PART V. UNCONVENTIONAL SOURCES OF ENERGY

Unconventional sources of energy are sources other than coal, oil, gas, wood, falling water, and now atomic energy. They include the sun's heat and light (solar energy), the wind (windpower), the tides (tidalpower), the heat within the earth, the thermal energy of the sea, bacterial life processes, and new exotic forms of generating electricity.

The subject is included here for the sake of completeness, and the treatment is brief.

SOLAR ENERGY

The traditional commercial uses of solar energy are in the evaporation of brine in open pans for recovery of the salt, in the drying of fruit, and to hasten plant growth in greenhouses. The attention to unconventional uses is with the intent of trying to capture and apply the heat to various other ends, depending on temperature desired, and for direct conversion into electricity. Low-temperature uses are many, including the heating of water (which then may be used for home heating, for example) and in the conversion of saline to fresh water. Solar conversion of saline water is one of the techniques being investigated by the Office of Saline Water of the Department of Interior. At higher temperatures the heat may be applied to furnaces or to run engines of various types—steam engines, for example—either for direct transmission of power or for generation of electricity.

The heat of the sun is caught by a reflector and focused where wanted. The focused beam can achieve temperatures of thousands of degrees, high enough to melt metals, and solar heat already has been used in experimental metallurgy.

Focused sunlight can be used in thermoelectric devices (creating an electric current by heating the junction of two dissimilar conductors). (See below.) A number of satellites are powered by photovoltaic cells (the kind used in photographic exposure meters), which are solid-state electronic devices that convert light into electricity. Other specialty uses are possible.

WINDPOWER

Windmills for pumping water are well-known devices, and the reference to windpower as an unconventional source of energy is to its widespread use, and mainly to produce electricity. Electric generators run by windmills are in commercial production or operation in Denmark, Canada, France, Germany, South Africa, the Soviet Union, the United States, the United Kingdom, and elsewhere. Interest is expanding.

Thousands of generators of capacity of 3 to 4 kilowatts are in use in different parts of the world. A 100-kilowatt wind-driven generator has been operating successfully in Denmark for several years, and a 100-kilowatt generator has been installed also in the Isle of Man.

A 640-kilowatt generator has been tested in France. All these larger units are designed to feed energy into existing alternating-current networks.

TIDAL ENERGY

Tidal energy is contemplated as a source of hydroelectric power wherever tides are abnormally high. The tides in the Passamaquoddy area of the Bay of Fundy have been viewed in that light for some time. A 235,000-kilowatt plant was proposed in 1924, and $7 million were spent on the project by the United States in 1935–36. The latest interest is expressed in a report of the International Joint Commission dated April 1961. A tide-driven prototype plant generating 9,000 kilowatts was inaugurated successfully in France (at Saint-Malo, Brittany) on November 4, 1959; interest is alive in a project on the La Rance River nearby that will have a capacity of 240,000 kilowatts, planned to deliver 97,000 kilowatts of winter power and 195,000 kilowatts of peak power. The U.S.S.R. is said to be interested in several projects, including one at Mezen on the White Sea.

THERMAL ENERGY OF THE SEA

Proposals have been advanced to make use of the difference in temperature between the surface water of the sea, heated by the sun, and the colder water below. Again, French engineers have been the leaders. The interest is based on the thermodynamic principle that heat can be converted to mechanical energy when there exists a difference in temperature between two heat sources. The temperature differential is analogous to head in a waterfall. The power that may be produced is proportional to the square of the difference, so that even small differences—if they are not too small—can be utilized. In certain ocean expanses, the temperature difference is consistently great enough, about 20°C., for this purpose.

GEOTHERMAL HEAT

Reservoirs of underground heat underlie the volcanic regions of the world. They are commonly identified by the presence of hot springs and fumaroles, and the heat can be withdrawn and used either in the form of hot water or steam under pressure. If the natural steam has sufficient volume, temperature, and pressure, it can be directed through a turbine to drive an electric generator, or the heat can be used to generate steam. Geothermal plants in Italy had a capacity of 274,000 kilowatts in 1954 and operated 300 days a year to provide 2 billion kilowatt-hours annually. A 275-kilowatt plant is in operation in the Katanga mining region. In Japan, New Zealand, Mexico, and Chile either plans have been made, designs drawn, or construction is in progress. The Pacific Gas & Electric Co. in 1959 placed a 12,500-kilowatt plant in operation at Sonoma, Calif., north of San Francisco, and has since expanded the capacity.

The steam fields of Iceland have long been used for heating purposes.

THE BACTERIAL FUEL CELL

The fuel cell, discussed more fully below, is included here as an unconventional source of energy because of the demonstration within

the past 2 years of a bizarre cell fueled with a common and harmless species of bacteria. The bacteria occur in and feed on almost any kind of organic matter and generate electricity in doing so: corncobs, peanut shells, the waste in polluted rivers. They occur everywhere, including abundantly in the sea. Cells generating 2 volts have been built, and model devices have been operated. An intriguing aspect is that the bacteria clean up organic waste matter in the process of converting it into electricity; a papermill, for example, might get its energy from its waste products and at the same time avoid polluting the river running by its door.

The bacteria fuel cell was discovered by a scientist of the Geological Survey—i.e., it is the result of Government research.

EXOTIC WAYS OF GENERATING ELECTRICITY

Five unconventional conversion methods are attracting considerable attention in scientific laboratories:

Thermionic converters, in which electrons "boiled out" of a hot metal surface are used to generate electricity. The device may appear soon in solar-power generators in satellites. One of the most hopeful applications, though at least a decade away, is in atomic powerplants, where the thermionic devices would use heat that is otherwise wasted in the steam-cycle. Such units would give added efficiency to power stations, augmenting the steam-turbine generator.

Thermoelectric generators, defined above. There is considerable talk about specialty applications but not much optimism about the generation of large amounts of economic power. Known materials do not offer any hope of efficiency above 10 percent, but the operation is simple and the materials would last indefinitely. Converse to the generation of electricity by heat, the passage of an electric current heats the conductor and, oddly enough, passage of the current in the opposite direction cools it. Thermoelectric cooling devices are already appearing commercially.

Magnetohydrodynamic generators (*MHD*), which use a hot steam of plasma (ionized gas) instead of a copper wire as the conductor. Few ideas of modern times have posed tougher materials problems. Some observers feel that there is little if any hope of finding an electrode material that can withstand the required temperatures for anything like the period of time that would make such devices economic for large powerplants, which is the field in which the application is usually talked about. Few specialty applications have been suggested. The idea is to combine MHD with conventional systems, to achieve higher efficiencies. Most observers judge that MHD is the least promising of the schemes discussed here.

Fuel cells, batterylike devices in which a chemical substance reacts to produce electricity without flame, smoke, or noise. In the fuel cell one of the chemicals is oxygen (pure or in the form of air), the other is hydrogen or an organic material. The chemicals are fed continuously into the cell, which is able therefore to generate electricity continuously and indefinitely.

The fuel cell is still an experimental idea, although close to some special commercial applications. Experimental fuel-cell tractors and forklift trucks have been tested. A small number of fuel cells are

being delivered to the Armed Forces; the first application might be for a backpack generator that can operate frontline electronic gear. Such specialty applications, where convenience is more important than cost, could become important soon. Bulk power generation (central station plants) would require a cell that operates on cheap hydrocarbon fuels (coal, oil, natural gas). Some experts believe such cells may be developed within a decade; others believe this is far too optimistic. The fuel cell for the home or for automotive use seems a long way off. In general there is more optimism about the fuel cell than about any of the other new energy conversion schemes.

DX 103

Comparison of Coal-Fired and Nuclear Power Plants For the TVA System

* * *

Conclusions

It is evident from the results of the evaluation that the nuclear alternatives have a decided advantage over the coal-fired plant and that either a BWR or a PWR nuclear plant at Browns Ferry would be a decided economic choice over a coal-fired plant at Cumberland City. Comparing the present values of the investment cost plus the total production costs for the first 12 years of plant operation of each of the alternatives indicates the amount of this saving is $21.9/kw for a PWR plant and $35.6/kw for a BWR over the coal-fired plant. Although the capacities of these plants are not identical, an indication of the magnitude of this saving in total dollars is helpful in appraising the alternatives. The dollars per kw saving above amounts to about $43 million if a PWR is installed instead of a coal-fired plant, and $76 million, if a BWR is installed. These represent annual savings of about $8 million for the BWR and $5 million for the PWR. In addition, the nuclear plants have firm prices covering all the equipment (for 1970 and 1971 operation), and firm prices for a longer period on the fuel supply.

There are no technical or other reasons to believe that either a fully operable plant of the BWR or PWR type cannot be successfully licensed and built. The choice then lies between the BWR and PWR. The BWR plant has a $13.7/kw economic advantage over the PWR; based on the capacity of the BWR plant the saving over the PWR has a present value for the first 12 years of about $29 million, or about $3 million annually, for the two-unit plant. In addition to this evaluated advantage over the PWR are GE's offers of a capacity guarantee, an operating assurance, better fuel cancellation terms, and a longer firm fuel supply.

* * *

Contract 41-T3 10-17-62 DX 104

Bart,

Enclosed is a draft of a letter which incorporates the basic information that I would like to have in your request for adding the Fidelity Mine as a source under this contract.

We will need the original and one copy of an executed Producer's Statement on the Fidelity Mine. The information that I have filled in on the form enclosed came from the statements that are on file for this source under Contract 38-T12.

You can probably improve on the language that I have suggested for the letter, but the idea is the thing I wanted to be sure was incorporated.

I certainly appreciate your cooperation in working with me to bring this matter to its proper conclusion. I feel that the contract is good for both of us and that we will certainly reap mutual benefits from it.

Elmer

DEFENDANT'S EXHIBIT 105

October 18, 1962

Mr. E. C. Hill, Chief
Coal Procurement Branch
TENNESSEE VALLEY AUTHORITY
1010 Georgia Avenue
Chattanooga, Tennessee

Subject: CONTRACT 63P-41-T3—Coal for Shawnee Steam Plant

Dear Mr. Hill:

Confirming our telephone conversation on October 17, 1962, we would appreciate being authorized to begin deliveries on the above contract effective October 22, 1962, rather than on the November 1, 1962, date which was established as the initial date when this contract award was made last week. Deliveries during October will be at the rate of 9,000 tons per week and increase to 13,000 tons per week effective November 1, as now provided under the agreement.

We also request that beginning with initial deliveries and continuing until further notice, we be permitted to deliver 50 per cent of the contract weekly schedule requirements from the Fidelity Mine of our affiliated company, The United Electric Coal Companies. The size and quality of coal to be furnished from this source and other data pertinent to this operation are set out on the enclosed Producer's Statement which is provided in duplicate. It would be agreeable with us if you prefer to provide for a separate guaranteed analysis and billing price

per ton on this Fidelity coal so as to minimize quarterly adjustments for quality.

We will deeply appreciate your cooperation in the arrangement of these matters.

Sincerely yours,

FREEMAN COAL MINING CORPORATION

BARTON R. GEBHART
Vice President

BRG:AJ

TENNESSEE VALLEY AUTHORITY
Division of Materials
Coal Procurement Branch
Chattanooga, Tennessee

COAL CONTRACT SUPPLEMENT

To Freeman Coal Mining Corporation
300 West Washington Street
Chicago 6, Illinois

Supplement No. 1
Date October 25, 1962
Contract No. 63P-41-73
Plant Shawnee
Name of Mine Various

Attention: Mr. Barton R. Gebhart

This confirms agreement reached between you and E. C. Hill by telephone on October 17, 1962, regarding the initial date of contract shipments and authorization of a supplemental mine source under above contract. This also acknowledges receipt of your letter dated October 18, 1962.

Initial deliveries shall begin under this contract on October 22, 1962, and continue for a period of 120 months thereafter. The Fidelity Mine is authorized as a supplemental source for up to 50 percent of weekly schedule requirements.

Information pertinent to the supplemental source in accordance with the Producer's Statement furnished is as follows:

Producer	United Electric Coal Companies
Mine	Fidelity
Seam	No. 6 (Illinois)
Type of mine	Strip
Size & preparation	*
Shipping point	Du Quoin, Illinois
Via	IC Railroad
Consigned to	Shawnee Steam Plant

*1-1/4" x 0 Segs. (moisture allowance 3%)
6" x 0 Cr. to 1-1/4" x 0 - mixed with 1-1/4" x 0 Segs. (moisture allowance 1%)
6" x 1-1/4" or int. sizes Cr. to 1-1/4" x 0 (moisture allowance none). All crushing after washing.

The guaranteed analysis for deliveries from the Fidelity Mine shall be as follows:

Total moisture	11.0%
Ash (dry basis)	11.1%
Sulphur (dry basis)	3.4%
Btu/lb. (dry basis)	12,653
Delivered heat content Btu/lb. (as received)	11,261
Btu/lb. (A&M free)	14,233

Effective October 22, 1962, the billing price TVA will pay for deliveries from the Fidelity Mine shall be $2.85 a ton f.o.b. rail cars, Du Quoin, Illinois. This change in price (to the nearest cent a ton) is correlative to the above change in the guaranteed analysis and the contract evaluated delivered cost of 18.00 cents a million

1002

TENNESSEE VALLEY AUTHORITY
Division of Materials
Coal Procurement Branch
Chattanooga, Tennessee

COAL CONTRACT SUPPLEMENT

-2-

To Freeman Coal Mining Corporation

Supplement No. 1
Date October 25, 1962
Contract No. 63P-41-73
Plant Shawnee
Name of Mine Various

Btu to the Shawnee Steam Plant (using a freight rate of $0.99 a ton). Your invoices should reflect the new billing price on shipments from the Fidelity Mine.

Separate samples shall be taken and separate Coal Quality Adjustment Reports will be issued each calendar quarter on receipts from the Fidelity Mine. The quarterly quality adjustment shall be applied to the billing price of the Fidelity Mine coal in the amount (calculated to the nearest cent a ton) necessary to preserve the delivered cost of 18.00 cents a million Btu at the Shawnee Steam Plant. The adjustment shall in no way be affected by subsequent changes in steam plant destination of the coal or in freight rates. (See contract Exhibit II for samples of calculations).

All other provisions of the contract remain unchanged.

Please complete the acceptance below and return the copy of this contract supplement to this office. You should retain the original for your file.

Accepted FREEMAN COAL MINING CORP.
Company

By [signature]

Title Vice-President

Date October 29, 1962

TENNESSEE VALLEY AUTHORITY

By [signature]
D. B. Stair
Contract Agent

DX 107

CENTRAL STATION NUCLEAR POWER

UNITS OPERABLE, UNDER CONSTRUCTION, OR ON ORDER

Contract Awarded	Operating Utility & Plant	State	Reactor Supplier	Size (Mw-Net)	Est. Cost* (Millions)	Power Operation	Regulatory Status**
1970	Cincinnati G. & E. Co. (Zimmer 2)1/	Ohio	GE	810	$ 187 8/	1976	230
	Georgia Pwr. Co. (Hatch 2)	Ga.	GE	786	200	1976	25?
	Southern California Ed. (San Onofre 2)	Cal.	Comb	1,100	} 450	1976	
	" " (" " 3)	Cal.	Comb	1,100		1977	440
	Virginia E. & P. Co. (No. Anna 2)1/	Va.	W	845	218 8/	1975	233
	(5 units)			4,641	$1,055		

1/ Considered a 1970 sale although the utility may consider the order to have been placed at the end of 1969.

See Other Notes on Page 3.

SUMMARY OF ORDERS BY YEAR OF CONTRACT AWARD

Contract Awarded	No. of Units Annual	No. of Units Cumulative	Capacity - Mw Annual	Capacity - Mw Cumulative
1953	1	1	90	90
1955	2	3	465	555
1956	1	4	175	730
1957	1	5	61	791
1958	3	8	130	921
1959	1	9	70	991
1962	2	11	625	1,616
1963	5	16	2,712	4,328
1965	7	23	4,361	8,689
1966	20	43	16,326	25,015
1967	31	74	25,935	50,950
1968	17	91	15,627	66,577
1969	7	98	7,139	73,716
1970 (3/31/70)	5	103	4,641	78,357

UTILITIES CONSIDERED LIKELY TO PLACE ORDERS IN 1970

Commonwealth Edison Co.
Consolidated Edison Co.
Eugene W. & E. Board
Jersey Central P. & L. Co.
Los Angeles D. W. & P.
Middle South Utilities
Pacific G. & E. Co.
South Carolina E. & G. Co.
Tennessee Valley Authority
Puerto Rico Wtr. Res. Auth.

AEC Division of Industrial Participation
March 31, 1970

CENTRAL STATION NUCLEAR POWER

UNITS OPERABLE, UNDER CONSTRUCTION, OR ON ORDER

Contract Awarded	Operating Utility & Plant	State	Reactor Supplier	Size (Mw-Net)	Est. Cost* (Millions)	Power Operation	Regulatory Status**
1953	Duquesne Lt. Co. (Shippingport 1)	Pa.	W	90a/	$ 60	1957	b/
1955	Commonwealth Edison Co. (Dresden 1)	Ill.	GE	200	$ 51	1960	O
	Consolidated Edison Co. (Indian Pt. 1)	N.Y.	B&W	265a/	124	1963	O
				465	$ 175		
1956	Yankee Atomic Electric Co. (Yankee)	Mass.	W	175	$ 39	1961	O
1957	Pwr. Reactor Development Co. (Fermi)	Mich.	PRDC	61	$ 60	1970	O
1958	Pacific G. & E. Co. (Humboldt Bay)	Cal.	GE	68	$ 24	1963	O
	Philadelphia Electric Co. (Peach Bottom 1)	Pa.	GGA	40	28	1967	O
	Rural Cooperative Pwr. Assoc. (Elk River)	Minn.	AC	22a/	14	1964	O
				130	$ 66		
1959	Consumers Pwr. Co. (Big Rock Pt.)	Mich.	GE	70	$ 25	1963	O
1962	Connecticut Yankee A. P. Co. (Conn. Yankee)	Conn.	W	575	$ 95	1967	O
	Dairyland Power Cooperative (LaCrosse)	Wisc.	AC	50	18	1969	O
				625	$ 113		
1963	Jersey Central P. & L. Co. (Oyster Creek 1)	N.J.	GE	530	$ 83	1969	O
	Los Angeles D. W. & P. (Malibu)	Cal.	W	462	92	1975	C/P
	Niagara Mohawk Pwr. Corp. (Nine Mile Pt.)	N.Y.	GE	500	151	1969	O
	Southern California Edison Co. (San Onofre)	Cal.	W	430	98	1967	O
	Washington Pub. Pwr. Sup. Sys. (NPR)	Wash.	-	790	315	1966	b/
	(5 units)			2,712	$ 739		
1965	Boston Edison Co. (Pilgrim)	Mass.	GE	625	$ 120	1971	C
	Commonwealth Edison Co. (Dresden 2)	Ill.	GE	809	84	1970	O
	Consolidated Edison Co. (Indian Pt. 2)	N.Y.	W	873	106	1971	O/P
	Florida P. & L. Co. (Turkey Pt. 3)	Fla.	W	652	70a/	1971	C
	Northeast Utilities (Millstone 1)	Conn.	GE	652	90	1970	O/P
	Public Ser. Co. of Colorado (Ft. St. Vrain)	Colo.	GGA	330	70	1972	C
	Rochester G. & E. Corp. (Robt. E. Ginna)	N.Y.	W	420	65	1969	O
	(7 units)			4,361	$ 605		
1966	Carolina P. & L. Co. (Robinson 2)	S.C.	W	700	$ 76	1970	O/P
	Commonwealth Edison Co. (Dresden 3)	Ill.	GE	809	82	1970	O/P
	" " (Quad Cities 1)	Ill.	GE	809	88	1970	O/P
	" " (" " 2)	Ill.	GE	809	82	1971	O/P
	Consumers Pwr. Co. (Palisades)	Mich.	Comb	700	110	1970	O/P
	Duke Pwr. Co. (Oconee 1)	S.C.	B&W	841	196a/	1971	C
	" " (" 2)	S.C.	B&W	886		1972	C
	Metropolitan Edison Co. (Three Mile Is.)	Pa.	B&W	831	162	1972	C
	Northern States Pwr. Syst. (Monticello)	Minn.	GE	545	88	1970	O/P
	Omaha Public Pwr. District (Ft. Calhoun)	Nebr.	Comb	457	120	1971	C
	Pacific G. & E. Co. (Diablo Canyon 1)	Cal.	W	1,060	154	1972	C
	Philadelphia Electric Co. (Peach Bottom 2)	Pa.	GE	1,065	163	1972	C
	" " (" " 3)	Pa.	GE	1,065	145	1973	C
	Public Ser. E. & G. Co. (Salem 1)	N.J.	W	1,050	140a/	1972	C
	T. V. A. (Browns Ferry 1)	Ala.	GE	1,064	330a/	1971	C
	" (" " 2)	Ala.	GE	1,064		1972	C
	Vermont Yankee N. P. Corp. (Vt. Yankee)	Vt.	GE	514	133	1971	C
	Virginia E. & P. Co. (Surry 1)	Va.	W	780	165	1971	C
	" " (" 2)	Va.	W	780	123	1971	C
	Wisconsin Michigan Pwr. Co. (Pt. Beach 1)	Wisc.	W	497	61	1970	O/P
	(20 units)			18,325	$ 2,424		

See Notes on Page 3

CENTRAL STATION NUCLEAR POWER

UNITS OPERABLE, UNDER CONSTRUCTION, OR ON ORDER

Contract Awarded	Operating Utility & Plant	State	Reactor Supplier	Size (Mwe-Net)	Est. Cost* (Millions)	Power Operation	Regulatory Status**
1967	Arkansas P. & L. Co. (Nuclear One)	Ark.	B&W	850	$ 132	1972	C
	Baltimore G. & E. Co. (Calvert Cliffs 1)	Md.	Comb	800	124	1973	C
	" " " " (" " 2)	Md.	Comb	800	105	1974	C
	Commonwealth Edison Co. (Zion 1)	Ill.	W	1,050	206	1972	C
	" " " (" 2)	Ill.	W	1,050	198	1973	C
	Consolidated Edison Co. (Indian Pt. 3)	N.Y.	W	965	156	1973	C
	Duke Pwr. Co. (Oconee 3)	S.C.	B&W	886	83 f/	1973	C
	Duquesne Ltg. Co. (Beaver Valley 1)	Pa.	W	847	189	1973	C/P
	Florida P. & L. Co. (Turkey Pt. 4)	Fla.	W	652	70 d/	1972	C
	" " " (Hutchinson Is. 1)	Fla.	Comb	800	123	1973	C/P
	Florida Pwr. Corp. (Crystal River 3)	Fla.	B&W	858	149	1972	C
	Georgia Pwr. Co. (Hatch 1)	Ga.	GE	786	151	1973	C
	Indiana & Mich. Electric Co. (D.C. Cook 1)	Mich.	W	1,054	} 235	1972	C
	" " " " (" " 2)	Mich.	W	1,060		1973	C
	Jersey Central P. & L. Co. (Three Mile Is. 2)	N.J.	B&W	810	108	1974	C
	Long Island Lighting Co. (Shoreham)	N.Y.	GE	819	218	1975	C/P
	Maine Yankee A. P. Co. (Maine Yankee)	Me.	Comb	790	161	1972	C
	Nebraska Pub. Pwr. Dist. (Cooper)	Nebr.	GE	778	127	1972	C
	New York State E. & G. Corp. (Bell)	N.Y.	GE	838	166	(no date)	C/P
	Northern Indiana Pub. Ser. Co. (Bailly)	Ind.	GE	640	103	1976	-
	Northern States Pwr. Co. (Prairie Is. 1)	Minn.	W	530	} 186	1972	C
	" " " (" " 2)	Minn.	W	530		1974	C
	Northeast Utilities (Millstone 2)	Conn.	Comb	828	179	1974	C/P
	Philadelphia Electric Co. (Limerick)	Pa.	GE	1,065	252	1976	C/P
	" " " (")	Pa.	GE	1,065	226	1977	C/P
	Public Ser. E. & G. Co. (Salem 2)	N.J.	W	1,090	140 d/	1973	C
	Sacramento Mun. Util. Dist. (Rancho Seco)	Cal.	B&W	800	134	1973	C
	T. V. A. (Browns Ferry 3)	Ala.	GE	1,065	130 f/	1972	C
	Virginia E. & P. Co. (No. Anna 1)	Va.	W	845	209 e/	1974	C/P
	Wisconsin Michigan Pwr. Co. (Pt. Beach 2)	Wisc.	W	497	94	1971	O/P
	Wisconsin Pub. Ser. Corp. (Kewaunee)	Wisc.	W	527	109	1972	C
	(31 units)			25,935	$ 4,435		
1968	Carolina P. & L. Co. (Brunswick 1)	N.C.	GE	821	$ } 303	1974	C
	" " " (" 2)	N.C.	GE	821		1976	C
	" "	N.C.	GE	821	164	(no date)	-
	Consolidated Edison Co. (Verplanck 1)	N.Y.	GE	1,115	221	1976	C/P
	Consumers Pwr. Co. (Midland 1)	Mich.	B&W	492	} 337	1973	C/P
	" " " (" 2)	Mich.	B&W	818		1974	C/P
	Detroit Edison Co. (Fermi 2)	Mich.	GE	1,123	221	1973	C/P
	Iowa Electric Lt. & Pwr. Co. (D. Arnold)	Iowa	GE	545	133	1973	C/P
	Pacific G. & E. Co. (Diablo Canyon 2)	Cal.	W	1,060	186	1974	C/P
	Pennsylvania P. & L. Co.	Pa.	GE	1,052	150	1975	-
	" " "	Pa.	GE	1,052	150	1977	-
	Portland General Electric Co. (Trojan)	Oreg.	W	1,106	199	1974	C/P
	Pwr. Auth. of New York (FitzPatrick)	N.Y.	GE	821	226	1973	C/P
	Pub. Ser. Co. of New Hampshire (Seabrook)	N.H.	W	860	186	(no date)	C/P
	T. V. A. (Sequoyah 1)	Tenn.	W	1,124	} 332	1973	C/P
	" (" 2)	Tenn.	W	1,124		1974	C/P
	Toledo Edison Co. (Davis-Besse)	Ohio	B&W	872	201	1974	C/P
	(17 units)			15,627	$ 3,076		
1969	Alabama Pwr. Co. (Farley)	Ala.	W	829	$ 184	1975	C/P
	Cincinnati G. & E. Co. (Zimmer 1)	Ohio	GE	810	197 e/	1975	-
	Duke Pwr. Co. (Lake Norman)	N.C.	W	1,100	} 372	1975	-
	" " (" ")	N.C.	W	1,100		1977	-
	Jersey Central P. & L. Co. (Oyster Crk. 2)	N.J.	Comb	1,100	260	1976	-
	Pub. Ser. E. & G. Co. (Newbold Is. 1)	N.J.	GE	1,100	} 491	1975	C/P
	" " " " (" " 2)	N.J.	GE	1,100		1977	C/P
	(7 units)			7,139	$ 1,504		
	TOTAL THROUGH 1969 (98 units)			73,716	$13,258		

*Figures indicate total construction cost, including land and land rights. Transmission plant, fuel, training, and R&D excluded.

**O - Operating License, O/P - Operating License Pending, C - Construction Permit, C/P - Construction Permit Pending

a/ Limit of T-G capacity. Reactor power 135 Mwe.

b/ Includes capacity of fossil fueled superheater. Electric power from reactor only: Indian Point - 151 Mwe; Elk River - 16 Mwe.

c/ Operable - License not required.

d/ One-half total cost for two units.

e/ 70% of total cost for three units.

f/ 30% of total cost for three units.

AEC Division of Industrial Participation
March 31, 1970

1969 ANNOUNCEMENTS OF NEW STEAM-ELECTRIC PLANT ADDITIONS*

Operating Utility and Plant	Capacity, Mwe Fossil	Capacity, Mwe Nuclear	Power Operation
Alabama Pwr. Co. (Farley)		829	1975
American Electric Pwr. Co.	1,300		-
" " "	1,300		-
" " "	1,300		-
Appalachian Pwr. Co.	1,300		-
Associated Electric Co-op (Springfield, Mo.)	600		1972
Cambridge Electric Lt. Co. (Canal 2)	800		-
Carolina P. & L. Co. (Roxboro 3)	720		1973
" " (Sutton)	420		1972
Central Hudson G. & E. Corp. (Roseton 1)	600		1972
" " " (" 2)	600		1973
Central P. & L. Co.	325		1974
Dayton P. & L. Co. (Stuart 4)	600		1975
Detroit Edison Co. (Monroe 4)	786		1973
Duke Pwr. Co. (Belews Creek 1)	1,144		1974
" " (" " 2)	1,144		1975
" " (Cliffside 5)	575		1972
" "		1,100	1977
" "		1,100	1979
Duquesne Lt. Co./Ohio Edison Co.	800		1975
" " " "	800		1976
Florida P. & L. Co. (Sanford 4)	398		1972
" "	398		1972
Gulf Pwr. Co. (Crist 7)	500		1973
Houston Ltg. & Pwr. Co.	750		1973
Jersey Central P. & L. Co. (Union Beach 1)	400		1973
" " " (" " 2)	400		1974
Kentucky Utilities Co. (Ghent 1)	427		1974
Minnesota P. & L. Co. (Boswell 3)	350		1973
Mississippi Pwr. Co. (Watson 5)	505		1973
Mississippi P. & L. Co.	750		1975
New England Electric System	465		1973
New Madrid, Missouri (New Madrid 1)	600		1972
Northeast Utilities	402		1973
Northern Indiana Pub. Ser. Co. (Bailly 12)	500		1973
" " " "	500		1975
Orange & Rockland Utilities, Inc. (Bowline 1)	600		1972
Orlando, Florida (Indian River 3)	327		1973
Otter Tail Pwr. Co.	400		1975
Pacific P. & L. Co.	500		1974
" "	500		1975
" "	500		1976
Philadelphia Electric Co.	400		1974
Public Ser. Co. of Colorado (Comanche 1)	360		1973
Public Ser. Co. of Indiana, Inc.	600		1974
" " "	600		1975
Public Ser. Co. of New Hampshire	400		1974
Public Ser. E. & G. Co.		1,100	1975
" " "		1,100	1977
Puerto Rico Water Res. Authority	500		1974
" " " " "	500		1975
Salt River Pwr. District (Navaho 1)	770		1974
" " " " (" 2)	770		1975
" " " " (" 3)	770		1976
Seattle City Light/Snohomish PUD		1,000	1979
Southern Calif. Edison Co. (Huntington Beach 7)	790		1973
" " " (" " 8)	790		1974
Tampa Electric Co.	434		1973
Texas Electric Ser. Co. (Permia Basin 6)	540		1974
Union Electric Co.	600		1975
" "	600		1976
Utah P. & L. Co.	330		1974
" "	500		-
" "	500		-
" "	500		-
" "	500		-
Total Each	37,040	6,229	
Total - %	86%	14%	
Total Fossil & Nuclear	43,269		

* Units under 300 Mwe and gas-turbine installations are not included.

AEC Division of Industrial Participation
March 31, 1970

CENTRAL STATION NUCLEAR POWER

UNITS OPERABLE, UNDER CONSTRUCTION, OR ON ORDER

Power Operation	No. of Units Annual	No. of Units Cumulative	Capacity - Mwe Annual	Capacity - Mwe Cumulative
Thru 1965	-	7	-	890
1966	1	8	790	1,680
1967	3	11	1,045	2,725
1968	-	11	-	2,725
1969	4	15	1,500	4,225
1970	9	24	5,582	9,807
1971	11	35	7,892	17,699
1972	17	52	14,440	32,139
1973	16	68	14,214	46,353
1974	11	79	9,614	55,967
1975	9	88	8,082	64,049
1976	7	95	6,372	70,421
1977	5	100	5,417	75,838
1978	-	100	-	75,838
1979	-	100	-	75,838
No Completion Date	3	103	2,519	78,357

SUMMARY OF REACTOR ORDERS

	No.	Capacity Mwe	%
Babcock & Wilcox	12	9,200	12
Combustion Engineering	10	8,475	10
General Electric	39	31,031	40
Gulf General Atomic	2	370	1
Westinghouse	36	28,349	36
*Other	4	923	1
TOTAL (3/31/70)	103	78,357	100

* Fermi, Elk River, LaCrosse, NPR

SUMMARY OF ANNOUNCEMENTS OF NEW STEAM-ELECTRIC PLANT ADDITIONS

Announcements in	FOSSIL Mwe	FOSSIL %	NUCLEAR Mwe	NUCLEAR %	TOTAL
1965	15,928	73	6,009	27	21,937
1966	20,096	47	22,477	53	42,573
1967	32,320	55	26,460	45	58,780
1968	24,600	62	14,803	38	39,403
1969	37,060	86	6,229	14	43,289
(5 Year Total)	129,984	63	75,978	37	205,962

AEC Division of Industrial Participation
March 31, 1970

DEFENDANT'S EXHIBIT 108

AEC

UNITED STATES
ATOMIC ENERGY COMMISSION
WASHINGTON, D.C.

No. N-2
Tel. 973-3446 (Info.)
973-5371 (Copies)

FOR IMMEDIATE RELEASE
(Tuesday, January 13, 1970)

JAN 14 1970

NOTE TO EDITORS AND CORRESPONDENTS:

Following is a brief status report on U. S. civilian nuclear power plants for the year 1969:

During the year, electric utilities made known plans for six nuclear power plants. In this period, the utilities ordered seven reactors (five for plants announced during the year and two for plants previously announced) with a total capacity of about 7,169,000 kilowatts.

In 1968, utilities made known plans for 17 nuclear power plants. They also ordered 17 reactors with a total capacity of about 15,630,000 kilowatts.

Status of all nuclear power plants, as of December 31, 1969

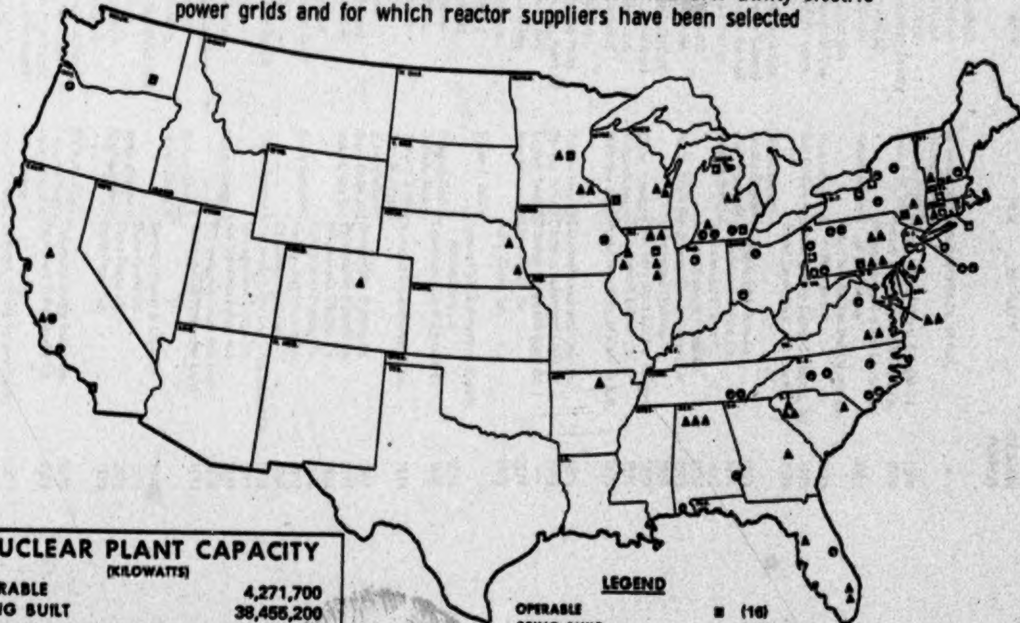
	kilowatts
16 operable	4,271,700
48 being built	38,455,200
34 planned (reactors ordered)	30,883,000
8 planned (reactors not ordered)	7,645,000
Total	81,254,900

Attached for your information is a map of the United States showing the location of all present and proposed civilian nuclear power plants for which reactor suppliers have been selected.

#

NUCLEAR POWER PLANTS IN THE UNITED STATES

The nuclear power plants included in this map are ones whose power is being transmitted or is scheduled to be transmitted over utility electric power grids and for which reactor suppliers have been selected



NUCLEAR PLANT CAPACITY
(KILOWATTS)

OPERABLE		4,271,700
BEING BUILT		38,455,200
PLANNED	REACTORS ORDERED	30,883,000
	REACTORS NOT ORDERED	7,645,000
	TOTAL	81,254,900

ELECTRIC UTILITY CAPACITY BY CONVENTIONAL MEANS AS OF OCT. 31, 1969: 323,610,431 KILOWATTS

LEGEND

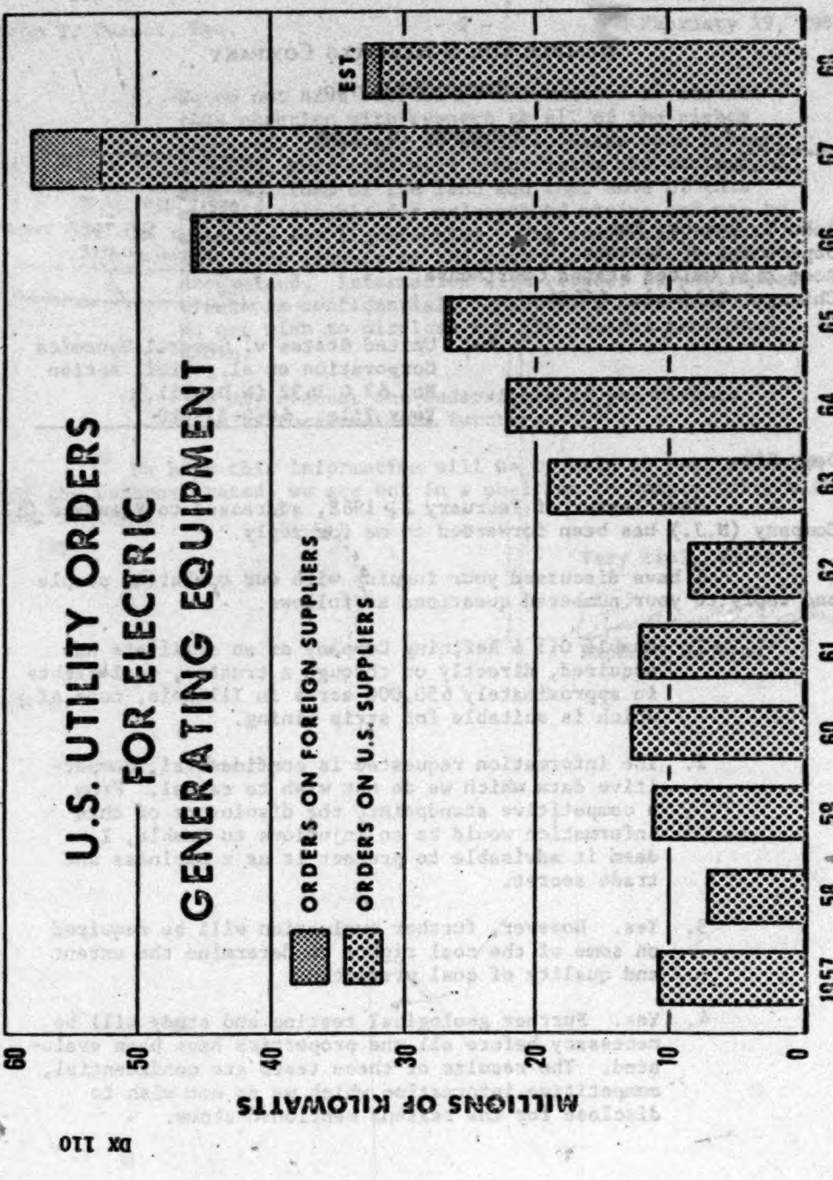
OPERABLE	■	(16)
BEING BUILT	▲	(48)
*PLANNED (Reactors Ordered)	●	(34)

*8 more plants have been announced for which reactors have not yet been ordered.

U.S.Atomic Energy Commission
December 31, 1969

SITE	PLANT NAME	CAPACITY (Kilowatts)	UTILITY	INITIAL DESIGN POWER
ALABAMA				
Decatur	Browns Ferry Nuclear Power Plant: Unit 1	1,064,500	Tennessee Valley Authority	1971
Decatur	Browns Ferry Nuclear Power Plant: Unit 2	1,064,500	Tennessee Valley Authority	1972
Decatur	Browns Ferry Nuclear Power Plant: Unit 3	1,064,500	Tennessee Valley Authority	1972
Houston County	Joseph M. Farley Nuclear Plant	829,000	Alabama Power Co.	1975
ARKANSAS				
London	Arkansas Nuclear One	850,000	Arkansas Power & Light Co.	1972
CALIFORNIA				
Humboldt Bay	Humbolt Bay Power Plant: Unit 3	68,500	Pacific Gas & Electric Co.	1963
San Clemente	San Onofre Nuclear Generating Station	430,000	Southern Calif. Edison and San Diego Gas & Electric Co.	1967
Corral Canyon	Malibu Nuclear Plant: Unit 1	462,000	L.A. Dept of Water & Power	1975
Diablo Canyon	Diablo Canyon Nuclear Power Plant: Unit 1	1,060,000	Pacific Gas & Electric Co.	1973
Diablo Canyon	Diablo Canyon Nuclear Power Plant: Unit 2	1,060,000	Pacific Gas & Electric Co.	1974
Clay Station	Rancho Seco Nuclear Generating Station	800,000	Sacramento Municipal District	1972
COLORADO				
Platteville	Ft. St. Vrain Nuclear Generating Station	330,000	Public Service Co. of Colorado	1972
CONNECTICUT				
Haddam Neck	Conn. Yankee Atomic Power Plant	575,000	Conn. Yankee Atomic Power Co.	1967
Waterford	Millstone Nuclear Power Station: Unit 1	652,100	Northeast Utilities	1970
Waterford	Millstone Nuclear Power Station: Unit 2	828,000	Northeast Utilities	1974
FLORIDA				
Turkey Point	Turkey Point Station: Unit 3	651,500	Florida Power & Light Co.	1971
Turkey Point	Turkey Point Station: Unit 4	651,500	Florida Power & Light Co.	1972
Red Level	Crystal River Plant: Unit 3	858,000	Florida Power Corp.	1972
Ft. Pierce	Hutchinson Island	800,000	Florida Power and Light Co.	1973
GEORGIA				
Baxley	Edwin I. Hatch Nuclear Plant	786,000	Georgia Power Co.	1973
ILLINOIS				
Morris	Dresden Nuclear Power Station: Unit 1	200,000	Commonwealth Edison Co.	1960
Morris	Dresden Nuclear Power Station: Unit 2	809,000	Commonwealth Edison Co.	1970
Morris	Dresden Nuclear Power Station: Unit 3	809,000	Commonwealth Edison Co.	1970
Zion	Zion Nuclear Plant: Unit 1	1,050,000	Commonwealth Edison Co.	1971
Zion	Zion Nuclear Plant: Unit 2	1,050,000	Commonwealth Edison Co.	1973
Cordova	Quad-Cities Station: Unit 1	809,000	Comm. Ed. Co.–Ia.–Ill. Gas & Elec. Co.	1970
Cordova	Quad-Cities Station: Unit 2	809,000	Comm. Ed. Co.–Ia.–Ill. Gas & Elec. Co.	1971
INDIANA				
Dunes Acres	Bailly Generating Station	515,000	Northern Indiana Public Service Co.	1976
IOWA				
Cedar Rapids	Duane Arnold Energy Center: Unit 1	545,000	Iowa Electric Light and Power Co.	1973
MAINE				
Wiscasset	Maine Yankee Atomic Power Plant	790,000	Maine Yankee Atomic Power Co.	1972
MARYLAND				
Lusby	Calvert Cliffs Nuclear Power Plant: Unit 1	800,000	Baltimore Gas and Electric Co.	1973
Lusby	Calvert Cliffs Nuclear Power Plant: Unit 2	800,000	Baltimore Gas and Electric Co.	1974
MASSACHUSETTS				
Rowe	Yankee Nuclear Power Station	175,000	Yankee Atomic Electric Co.	1961
Plymouth	Pilgrim Station	625,000	Boston Edison Co.	1971
MICHIGAN				
Big Rock Point	Big Rock Point Nuclear Plant	70,300	Consumers Power Co.	1963
South Haven	Palisades Nuclear Power Station	700,000	Consumers Power Co.	1970
Lagoona Beach	Enrico Fermi Atomic Power Plant: Unit 1	60,900	Detroit Edison Co.	1963
Lagoona Beach	Enrico Fermi Atomic Power Plant: Unit 2	1,126,000	Detroit Edison Co.	1974
Bridgman	Donald C. Cook Plant: Unit 1	1,054,000	Indiana & Michigan Electric Co.	1972
Bridgman	Donald C. Cook Plant: Unit 2	1,060,000	Indiana & Michigan Electric Co.	1973
Midland	Midland Nuclear Power Plant: Unit 1	492,000	Consumers Power Co.	1973
Midland	Midland Nuclear Power Plant: Unit 2	818,000	Consumers Power Co.	1974
MINNESOTA				
Elk River	Elk River Nuclear Plant	22,000	Rural Cooperative Power Assoc.	1964
Monticello	Monticello Nuclear Generating Plant	545,000	Northern States Power Co.	1970
Red Wing	Prairie Island Nuclear Generating Plant: Unit 1	530,000	Northern States Power Co.	1972
Red Wing	Prairie Island Nuclear Generating Plant: Unit 2	530,000	Northern States Power Co.	1974
NEBRASKA				
Fort Calhoun	Ft. Calhoun Station: Unit 1	457,400	Omaha Public Power District	1971
Brownville	Cooper Nuclear Station	778,000	Consumers Public Power District and Iowa Power and Light Co.	1972
NEW HAMPSHIRE				
Seabrook	Seabrook Nuclear Station	860,000	Public Service Co. of N.H.	—
NEW JERSEY				
Toms River	Oyster Creek Nuclear Power Plant: Unit 1	515,000	Jersey Central Power & Light Co.	1969
Toms River	Oyster Creek Nuclear Power Plant: Unit 2	1,100,000	Jersey Central Power & Light Co.	1976
Salem	Salem Nuclear Generating Station: Unit 1	1,050,000	Public Service Gas and Electric Co. of New Jersey	1972
Salem	Salem Nuclear Generating Station: Unit 2	1,050,000	Public Service Gas and Electric Co. of New Jersey	1973
Newbold Island		1,100,000	Public Service Gas and Electric, NJ	1975
Newbold Island		1,100,000	Public Service Gas and Electric, NJ	1977
NEW YORK				
Indian Point	Indian Point Station: Unit 1	265,000	Consolidated Edison Co.	1963
Indian Point	Indian Point Station: Unit 2	873,000	Consolidated Edison Co.	1971
Indian Point	Indian Point Station: Unit 3	965,300	Consolidated Edison Co.	1973
Scriba	Nine Mile Point Nuclear Station	500,000	Niagara Mohawk Power Co.	1969
Rochester	R.E.Ginna Nuclear Power Plant: Unit 1	420,000	Rochester Gas & Electric Co.	1969
Shoreham	Shoreham Nuclear Power Station	819,000	Long Island Lighting Co.	1975
Lansing	Bell Station	838,000	New York State Electric & Gas Co.	1978
Verplanck	Verplanck: Unit 1	1,115,000	Consolidated Edison Co.	1975
Scriba	James A. Fitzpatrick Nuclear Power Plant	821,000	Power Authority of State of N.Y.	1973
NORTH CAROLINA				
Southport	Brunswick Steam Electric Plant: Unit 1	821,000	Carolina Power and Light Co.	1975
Southport	Brunswick Steam Electric Plant: Unit 2	821,000	Carolina Power and Light Co.	1976
*		821,000	Carolina Power and Light Co.	—
*		1,100,000	Duke Power Co.	1977
*		1,100,000	Duke Power Co.	1979
OHIO				
Oak Harbor	Davis-Besse Nuclear Power Station	872,000	Toledo Edison-Cleveland Electric Illuminating Co.	1974
Moscow	William H. Zimmer Nuclear Power Station	840,000	Cincinnati Gas & Electric Co	1975
OREGON				
Rainier	Trojan Station	1,106,000	Portland General Electric Co.	1974
PENNSYLVANIA				
Peach Bottom	Peach Bottom Atomic Power Station: Unit 1	40,000	Philadelphia Electric Co.	1967
Peach Bottom	Peach Bottom Atomic Power Station: Unit 2	1,065,000	Philadelphia Electric Co.	1971
Peach Bottom	Peach Bottom Atomic Power Station: Unit 3	1,065,000	Philadelphia Electric Co.	1973
Limerick Township		1,065,000	Philadelphia Electric Co.	1975
Limerick Township		1,065,000	Philadelphia Electric Co.	1977
Shippingport	Shippingport Atomic Power Station: Unit 1	90,000	Duquesne Light Co.	1957
Shippingport	Beaver Valley Power Station: Unit 1	847,000	Duquesne Light Co.–Ohio Edison Co.	1973
Goldsborough	Three Mile Island Nuclear Station: Unit 1	831,000	Metropolitan Edison Co.	1971
Goldsborough	Three Mile Island Nuclear Station: Unit 2	810,000	Metropolitan Edison Co.	1973
*	—	1,052,000	Pennsylvania Power and Light	1976
*	—	1,052,000	Pennsylvania Power and Light	1977
SOUTH CAROLINA				
Hartsville	H.B. Robinson S.E. Plant: Unit 2	700,000	Carolina Power & Light Co.	1970
Seneca	Oconee Nuclear Station: Unit 1	841,100	Duke Power Co.	1971
Seneca	Oconee Nuclear Station: Unit 2	886,000	Duke Power Co.	1972
Seneca	Oconee Nuclear Station: Unit 3	886,000	Duke Power Co.	1973
TENNESSEE				
Daisy	Sequoyah Nuclear Power Plant: Unit 1	1,124,000	Tennessee Valley Authority	1973
Daisy	Sequoyah Nuclear Power Plant: Unit 2	1,124,000	Tennessee Valley Authority	1974
VERMONT				
Vernon	Vermont Yankee Generating Station	513,900	Vermont Yankee Nuclear Power Corp.-Green Mt. Power Corp.	1971
VIRGINIA				
Gravel Neck	Surry Power Station: Unit 1	780,000	Virginia Electric & Power Co.	1971
Gravel Neck	Surry Power Station: Unit 2	780,000	Virginia Electric & Power Co.	1971
Mineral	North Anna Power Station: Unit 1	845,000	Virginia Electric & Power Co.	1974
WASHINGTON				
Richland	N-Reactor/WPPSS Steam	790,000	Washington Public Power Supply System	1966
WISCONSIN				
Genoa	LaCrosse Boiling Water Reactor	50,000	Dairyland Power Cooperative	1969
Two Creeks	Point Beach Nuclear Plant: Unit 1	497,000	Wisconsin Michigan Power Co.	1970
Two Creeks	Point Beach Nuclear Plant: Unit 2	497,000	Wisconsin Michigan Power Co.	1972
Carlton	Kewaunee Nuclear Power Plant: Unit 1	527,000	Wisconsin Public Service Co.	1972

* Site not selected.


U.S. UTILITY ORDERS FOR ELECTRIC GENERATING EQUIPMENT
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ORDERS ON U.S. SUPPLIERS
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DX 110

HUMBLE OIL & REFINING COMPANY

HOUSTON, TEXAS 77001

February 19, 1968

RICHARD P. RYAN
GENERAL COUNSEL

60-0-37-920
DEPARTMENT OF JUSTICE
FEB 26 1968
DIVISION OF RECORDS

John T. Cusack, Esq.
Department of Justice
Room 2634 United States Courthouse
Chicago, Illinois 60604

Re: United States v. General Dynamics Corporation et al., Civil Action No. 67 C 1632 (N.D. Ill.)
Your file: 60-0-37-920

Dear Sir:

Your letter of February 2, 1968, addressed to Standard Oil Company (N.J.) has been forwarded to me for reply.

I have discussed your inquiry with our operating people and reply to your numbered questions as follows:

1. Humble Oil & Refining Company or an affiliate has acquired, directly or through a trustee, coal rights in approximately 650,000 acres in Illinois, none of which is suitable for strip mining.

2. The information requested is confidential, competitive data which we do not wish to reveal. From a competitive standpoint, the disclosure of this information would be so injurious to Humble, I deem it advisable to protect it as a business and trade secret.

3. Yes. However, further evaluation will be required on some of the coal rights to determine the extent and quality of coal present.

4. Yes. Further geological testing and study will be necessary before all the properties have been evaluated. The results of these tests are confidential, competitive information which we do not wish to disclose for the reasons mentioned above.

John T. Cusack, Esq. - 2 - February 19, 1968

5. We do not have sufficient information to answer this question with respect to all of the rights acquired. However, it appears, based upon present studies, that coal will occur below the surface of some portions of the land and that some of this coal is suitable for underground mining and may be suitable for liquefaction. The commercial feasibility of liquefying the coal has not yet been determined. Information with respect to particular tracts is confidential, competitive data which we do not wish to disclose for the reasons mentioned above.

6. You may contact the undersigned if you wish to discuss these matters further.

We hope this information will be of help to you, although for the reasons stated, we are not in a position to comply fully with your request.

Very truly yours,

Richard P. Ryan

Richard P. Ryan

RPR:ab

1014

HUMBLE OIL & REFINING COMPANY

HOUSTON, TEXAS 77001

February 22, 1968

RICHARD P. RYAN
GENERAL COUNSEL

FEB 29 1968

Mr. Ron Futterman
Department of Justice
Room 2634 United States Courthouse
Chicago, Illinois 60604

Re: United States v. General Dynamics Corporation et al., Civil Action No. 67 C 1632 (N.D. Ill.)
Your file: 60-0-37-920

Dear Sir:

Following your telephone call Tuesday afternoon I asked our operating people for a statement of our purpose in acquiring coal reserves in Illinois.

I found that they look upon these coal reserves as a long-range source of raw material that may be converted into hydrocarbon products, such as gasoline. We are also considering the possibility of making some sales of coal to utilities tributary to our reserves.

I trust this answers the question you raised in our telephone conversation.

Very truly yours,

Richard P. Ryan

Richard P. Ryan

RPR/nb

60-0-37-9-20
DEPARTMENT OF JUSTICE
FEB 23 1968
DIVISION OF RECORDS

DX 112

GENERAL DYNAMICS CORPORATION

Excerpt from Minutes of Meeting of Board of Directors

Held on September 30, 1966

---

7. United Electric Coal Companies - Purchase of Stock

The Chairman referred to the discussions at the last Board meeting regarding the purchase of additional stock of United Electric Coal Companies. He reported that, as authorized by the Board, the Corporation had acquired 48,400 shares of UEC from Material Service Employees Profit Sharing Trust at $50.50 a share, which represented the cost to the Trust of acquiring and carrying the stock.

The Chairman then stated that management had considered further the advisability of acquiring the remaining minority interest in UEC and, for various reasons, had concluded that the Corporation should proceed with a plan of acquisition at this time. He asked Mr. Sargent to present the management's views.

Mr. Sargent reviewed for the Directors the charts containing financial data on UEC which had been presented at the

last Board meeting, and noted the amounts that would be required on various assumptions to acquire the remainder of the UEC stock. He stated that the management still felt that the most direct method of acquiring the balance of the UEC stock was through a combination of a tender offer for an additional 170,000 UEC shares, which would bring the Corporation's holdings to slightly more than 90%, and a "short form" merger, available under Delaware law to a 90% holder, under which any remaining minority would be paid the fair value of their shares. He stated that under the "short form" merger provisions, UEC could be merged directly into the Corporation or into a new Delaware subsidiary to which the Corporation would first transfer its UEC shares, in either case by action of the Board of the parent. He stated that if the tender offer were a success the merger would be effected as promptly as possible and steps would be taken to provide management for UEC and to combine UEC and Freeman marketing and other administrative functions and staffs where efficiencies and cost reductions could be achieved. He stated, however, that in the first instance the UEC coal properties and contracts would be held separately from those of Freeman, most probably in the new Delaware subsidiary.

Mr. Sargent then reviewed the various considerations in support of the management view that the minority interest in UEC should be acquired and that Freeman and UEC should be combined as soon as possible, including a review of UEC's limited coal reserves and the resulting problems UEC had encountered in obtaining and keeping long term contracts, the ability of Freeman to provide a back-up of reserves over the long term and finally

the requirement for a new chief executive officer and other key personnel on which action should be taken promptly. He also reported that the New York Stock Exchange indicated its intention to delist UEC within the next few weeks. He stated that, in general, the combination of the two operations made good business and operating sense and would insure the ability of the enterprise to compete more effectively in its market. He stated further that, under all the circumstances, the Corporation's legal staff was not aware of any legal reason why the Corporation should not proceed with the plan.

The Directors discussed the matter of a tender offer price, in the course of which it was pointed out that it is normal in tenders of this kind to offer a premium over market of between 15% and 20%. Mr. Sargent then reviewed the market action of UEC stock over the last few months in which he noted that in July, when the possibility of a tender offer was first discussed, UEC was selling at 39-1/2, and that on August 3, the day before the meeting of the Board at which the tender offer was to be considered, the price of UEC had risen to 49. He stated that subsequent to the August meeting the price of the stock dropped sharply. The current market is about 42. Mr. Sargent then stated that, in his opinion, the Corporation should not, under present conditions, pay more than $50 a share on the tender offer, which provided a sufficient premium over the market. The consensus of the Directors was that $50 a share would be a proper offering price at this time.

Mr. Sargent answered questions by various Directors about the Corporation's cash position, the status of bank loans,

the effective rate of interest being paid, compensating balances, and all other factors relating to the Corporation's ability to finance the tender offer and the payout to the minority stockholders on the "short form" merger. The remaining Directors were polled and, in view of the business considerations detailed by management, all concurred in the recommendation to proceed with the tender offer.

Mr. Sargent stated that, as he had noted earlier, on a Delaware "short form" merger, the minority are entitled to be paid the fair value of their shares, exclusive of any element of value arising from the merger. In the first instance the Corporation or the Board of the new subsidiary would set the price, and any UEC share holder objecting to the price could seek appraisal under Delaware law. He stated that management did not have a final recommendation on the price to be offered on the merger, but that he was certain that it would not exceed $50 a share and might be less.

Mr. Sargent stated that it was proposed that Chase Manhattan Bank be designated as Tender Agent, that Georgeson & Co. be retained to assist on the tender offer and that a fee of 50 cents a share be paid to soliciting brokers. He then submitted to the meeting the proposed Invitation for Tender and Form of Tender and Assignment. He stated that these documents were substantially as submitted and reviewed at the August Board meeting, except that UEC earnings data for the first nine months of the year had been included. He stated that the documents had also been cleared with the New York Stock Exchange. The Chairman

directed that copies of the proposed Invitation for Tender and Form of Tender and Assignment be filed with the records of the meeting.

Mr. Sargent stated that, in addition to authorizing the tender offer and related action, it would be appropriate at this time for the Board to authorize the management, in its discretion, to organize a new Delaware subsidiary, to transfer the UEC stock to such subsidiary and to take such other action as would be required to effect the "short form" merger on the basis proposed. He stated that it was expected that the definitive plan for the combination of UEC and Freeman would be developed in time to permit its consummation by the end of the year.

After further discussion, on motion duly made, seconded, and unanimously carried, it was

> RESOLVED, that the Corporation make an offer (hereinafter in these resolutions called the Tender Offer) to purchase shares of Common Stock of The United Electric Coal Companies (hereinafter in these resolutions called UEC) by inviting tenders for such shares at a price of $50 per share in the manner and on the other terms set forth in the instruments hereinafter in these resolutions approved; and further
>
> RESOLVED, that the form, terms and provisions of the proposed Invitation for Tenders and the proposed Form of Tender and Assignment to be used in connection with the Tender Offer, copies of which have been submitted to this meeting, be, and hereby are, approved, with such changes therein as the President or the Vice President-Finance of the Corporation and Counsel for the Corporation may deem necessary or advisable and approve; and further
>
> RESOLVED, that The Chase Manhattan Bank, N.A., be, and hereby is, designated as Tender Agent of

the Corporation for the purposes of the Tender Offer; and further

RESOLVED, that the President, the Vice President-Finance or the Secretary of the Corporation be, and each of them hereby is, authorized to

(a) engage The Chase Manhattan Bank, N.A., as Tender Agent of the Corporation in connection with the Tender Offer:

(b) extend the termination date of the Tender Offer to such date (not later than November 21, 1968) as they or any of them shall determine;

(c) pay commissions or fees to brokers responsible for soliciting tenders of shares of Common Stock of UEC;

(d) retain solicitors to assist in connection with the Tender Offer;

(e) deliver to the Tender Agent such instructions as they or any of them shall deem necessary or proper in connection with the Tender Offer (which instructions shall designate the persons authorized to act for and on behalf of the Corporation in connection therewith); and

(f) take all such other action as they or any of them shall deem necessary, proper or advisable in connection with the Tender Offer and the implementation of these resolutions or any of them; and further

RESOLVED, that the President, the Vice President-Finance, or the Secretary of the Corporation be, and each of them hereby is, authorized to take all such action, in the name and on behalf of the Corporation, as shall be necessary or proper to

(a) at such time as the Corporation shall own not less than 90% of the outstanding stock of UEC, cause UEC to be merged into the Corporation and, in connection therewith, set the terms and conditions of the merger (provided that the consideration to be paid for shares of UEC shall not exceed $50 a share) and execute and file a certificate of ownership and merger, all in accordance with Section 253 of the Delaware General Corporation Law;

PRIVATE

(b) form a new corporation under the laws of the State of Delaware (hereinafter called New Corporation);

(c) execute, in the name and on behalf of the Corporation, a subscription agreement with New Corporation providing for the purchase by the Corporation of all the authorized capital stock of New Corporation for not more than $1000;

(d) as an alternative to the actions authorized pursuant to (a) above, transfer to New Corporation, as a capital contribution, all the shares of Common Stock of UEC owned by the Corporation (including, but not limited to, the shares of Common Stock of UEC to be purchased by the Corporation pursuant to the Tender Offer); and

(e) at such time as New Corporation shall own not less than 90% of the outstanding stock of UEC, cause UEC to be merged with and into New Corporation in accordance with Section 253 of the Delaware General Corporation Law upon such terms and conditions as said officers or any of them shall deem advisable, and in connection therewith to cause the Corporation to advance to New Corporation such funds as may be necessary to enable New Corporation to effect the terms of said merger.

THE UNITED ELECTRIC COAL COMPANIES DX 113

Special Meeting of the Board of Directors

October 9, 1959

A special meeting of the Board of Directors of

THE UNITED ELECTRIC COAL COMPANIES

was held at the office of the Company, 307 North Michigan Avenue, Chicago, Illinois, on the 9th day of October, 1959, at ten o'clock A. M., Central Daylight Saving Time, pursuant to waiver of notice.

The following directors were present:

John D. Ames
Dudley F. Jessopp
Frank F. Kolbe
John E. Martin
J. M. Morris

constituting a majority of the Board and a quorum.

Absent: Paul C. Clovis
J. Sterling Rockefeller
Henry A. Rudkin
George Spatta

The meeting was called to order by the President, Mr. Frank F. Kolbe, who presided throughout as Chairman of the meeting, and the minutes were recorded by Mr. G. H. Utterback, Secretary of the Company.

The Chairman suggested to the Board that a consideration of the minutes of the meeting of the Board of Directors held on September 21, 1959, be postponed to a later date.

The President then stated that certain large stockholders of the Company whose stock holdings aggregated approximately 50% of the Company's shares were requesting representation on the Board of Directors. He said that in the past he had offered representation

to them but that they had declined. He further stated that in order to meet such current request it would be necessary to eliminate five members of the present Board. He stated that the members of the present Board had agreed among themselves that Messrs. Frank F. Kolbe, J. M. Morris, John D. Ames and Dudley F. Jessopp should remain on the present Board, and that Messrs. Frank Nugent, Milton Falkoff, Reuben Thorson, Irving Crown and Barton R. Gebhart should be the other five nominees to be suggested by the management, and that a proxy statement should be issued by the management to solicit proxies for the election of such nine suggested nominees.

. . .

Thereupon, on motion duly made by Mr. Jessopp, and duly seconded by Mr. Ames, it was unanimously

> RESOLVED, that the action taken by this Board of Directors at its meeting held on July 10, 1959, authorizing the Secretary of this Company to mail to stockholders of record on September 30, 1959, a notice and proxy statement in the forms adopted at said meeting and a proxy naming Messrs. Rudkin, Ames and Kolbe as proxies therein, be and the same hereby is rescinded.

. . .

> FURTHER RESOLVED, that the Secretary of this Company be and he hereby is authorized and directed to cause the Transfer Agent for the common stock of this Company to mail as soon as reasonably possible after the date of this meeting, in accordance with the By-laws of this Company and the laws of the State of Delaware, to all stockholders of record as of the close of business September 30, 1959, addressed to them at their respective addresses as they appear on the books of this Company, a notice and proxy statement in substantially the following forms:

EXCERPTS FROM MINUTES OF
MEETINGS of May 13, 1960

The Chairman brought up for discussion the Company's ownership in McDonough and Schuyler Counties. At July 31, 1959 the Company owned or had contracts to purchase 2,529.10 acres of coal containing an estimated 8,976,117 tons and as of this date these figures have been increased to 3,339 acres of coal containing 11,530,000 tons. Inasmuch as the development of this field is probably some ten years in the future, it was decided not to pursue an aggressive purchasing policy in that area, but only to acquire acreage which might become available at not to exceed normal farm land prices in this area.

EXCERPT FROM MINUTES OF
MEETING OF JULY 15, 1960

Mr. Hepburn was invited into the meeting and, referring to a map that displayed the western part of Illinois, explained the Company's plan for acquiring #2 coal reserves in McDonough and Schuyler Counties where some 10,000,000 tons are already held in reserve. He stated that about a year ago a mining feasibility study was made of the property. A study of County records discloses that coal land options are being taken by two or three other companies. It was decided to review and revise the feasibility study to re-examine the advisability of pursuing a more active optioning program in the area.

EXCERPT FROM MINUTES OF MEETING HELD SEPTEMBER 9, 1960

than for any previous month. All mines were in good physical condition, with Fidelity being particularly improved by the new location with lower ratio and better stripping conditions in general. Banner Mine produced 38,474 tons and changes in the washing plant are still in progress.

Increased sales were due largely to greater purchases by power companies, particularly Commonwealth Edison and Illinois Power.

Some additional strip coal found at Mary Moore Mine, while of higher stripping ratio, will make it possible to keep the mine in operation for another 6 or 8 months and this is being considered.

The President stated that the Company is continuing to take options and leases on coal in the Beaucoup Field, acting as agent for the Aluminum Company of America. At a recent meeting officials of Alcoa indicated they planned to make the next expansion so as to use the coal reserve in Beaucoup Field. The total reserve is considerably greater than the 100 million tons allocated as a proper backlog for aluminum production and the officials expressed an interest in the possible development of a coal mine in the area prior to the need for an aluminum plant, the coal so produced to be sold in the industrial market when and if such a demand is forthcoming. Mr. Nugent stated that the engineers for Freeman Coal Mining Company could make a feasibility study for such a project when necessary.

There being no further business, on motion duly made by Mr. Jessopp, and duly seconded by Mr. Morris, the meeting was adjourned.

Secretary

BOARD OF DIRECTORS MEETING HELD OCTOBER 28, 1960

(c) To consult with the Auditors regarding the scope of the audit to be made by such Auditors and to determine other services to be rendered by such Auditors with respect to such audit and other affairs of the Company.

(d) From time to time to advise this Board in respect of the matters herein covered, and

(e) To exercise such other powers as from time to time shall be delegated to it by the Board and as shall be necessary or proper to make effective the provisions of this resolution.

FURTHER RESOLVED, that Mr. Milton Falkoff be and he hereby is designated the Chairman of said Committee.

Upon motion duly made by Mr. Nugent, and duly seconded by Mr. Falkoff, it was unanimously

RESOLVED, that the proper officers of this Company, for and on its behalf, be and they hereby are authorized and directed to place a purchase order for a 70 cubic yard stripping shovel costing approximately $2,800,000.00; and

FURTHER RESOLVED, that said order be subject to cancellation within 30 days from this date by payment of such expenditures as the manufacturer may have made during that time and which cannot be recouped by him.

The Chairman stated because of conversations in the past in regard to possible consolidation with another coal company in this area it might be well to give some consideration to the subject.

Thereupon, on motion duly made by Mr. Gebhart, and duly seconded by Mr. Thorson, Messrs. Nugent, Falkoff and Morris not voting, it was

RESOLVED, that a committee composed of Messrs. Nugent as Chairman, Falkoff and Morris be and they hereby are appointed to serve at the pleasure of this Board to investigate and report to this Board concerning such consolidation.

Mr. Morris reported that Midwest Towing Co., Inc. for the first nine months of 1960 had a net income of $71,514.00 as against $44,235.00 for the corresponding period in 1959. Revenue for this

Excerpt FROM MINUTES OF MEETING OF MARCH 10, 19(

Upon motion duly made by Mr. Nugent, and duly seconded by Mr. Ames, the following preambles and resolution were unanimously adopted:

WHEREAS, this Company on January 31, 1961 conveyed by Deed of Conveyance to James C. Sneed approximately 3¼ acres of land in Hopkins County, Kentucky, the total consideration being $2,500.00; and

WHEREAS, this Company completed its mining operations in this area some years ago and has no further use for the land;

NOW, THEREFORE, BE IT RESOLVED, that the action of the officers of this Company, for and on its behalf, in executing said Deed of Conveyance to James C. Sneed, upon the terms as set forth above, be and the same hereby is in all respects approved, ratified and confirmed.

Upon motion duly made by Mr. Nugent, and duly seconded by Mr. Crown, the following preambles and resolution were unanimously adopted:

WHEREAS, the proper officers of this Company on Jan. 27, 1961 entered into a coal lease with A. E. Gross and Margaret Gross covering the acquisition of minerals and the right to use the surface of approximately 12 acres of land in Vermilion County, Illinois, containing an estimated 95,400 tons of coal, the consideration being 27¢ per ton on the first 50,000 tons and 2¢ per ton on all over 50,000 tons, with advance royalty of $13,500.00, payable $7,000.00 on January 27, 1961, and $6,500.00 on August 1, 1961; and

WHEREAS, at a stripping ratio of about 12 to 1 there is an estimated mineable tonnage of 38,300 which at the minimum royalty of $13,500.00 will cost 35.3¢ per ton; and

WHEREAS, the acreage covered by the lease is necessary for proper continuous operation of the Mary Moore Mine;

NOW, THEREFORE, BE IT RESOLVED, that the action of the officers of this Company, for and on its behalf, in entering into the coal lease with A. E. Gross and Margaret Gross, upon the terms and conditions as set forth above, be and the same hereby is in all respects approved, ratified and confirmed.

Mr. Nugent raised the question of the Company's reserves of mineable strip coal. After considerable discussion, upon motion duly made and duly seconded, it was

RESOLVED, that Messrs. Frank Nugent, John Morris and Irving Crown be and they hereby are constituted a committee to study the Company's situation in regard to reserves and to make recommendations to the Board as to how further reserves should be acquired.

FURTHER RESOLVED, that Mr. Frank Nugent be and he hereby is delegated to serve as Chairman of such Committee.

In view of the fact that March is the second month of the third quarter of the fiscal year, Mr. Morris brought up for discussion the Management Incentive Bonus for said fiscal year, and it was decided to defer discussion on this subject until the Board meeting scheduled for May 12th.

Mr. Morris also raised the question as to whether it would be advisable to transfer to a Chicago bank the Trusteeship of The United Electric Coal Companies Employees' Profit Sharing Trust fund from The Chase Manhattan Bank in New York. The question was referred to Messrs. Falkoff and Jessopp to report back to the Board at its May 12th meeting.

Mr. Falkoff, Chairman of the Audit Committee, requested that, in view of Mr. Thorson's absence, the report of Haskins & Sells detailed audit for the year ended July 31, 1960 be deferred until the Board meeting scheduled for May 12th. Mr. Falkoff further requested that the appointment of auditors for the year ending July 31, 1961 be deferred until the Board meeting on May 12th.

Mr. Falkoff also recommended that in the future the detailed audit report be made available to the Audit Committee before the annual statement is approved for printing.

There being no further business, on motion duly made by Mr. Ames, and duly seconded by Mr. Morris, the meeting was adjourned.

[signature]
Secretary

EXCERPT FROM MINUTES OF MEETING ON MAY 12, 1961.

5. When and if requested by United Electric, Central Illinois Light Company will use coal from this storage pile and United Electric may curtail shipments to that extent, and when requested by United Electric, Central Illinois Light Company will put into storage additional coal, and by this arrangement, United Electric will be able to ship at times most beneficial to production and sales commitments.

6. On coal withdrawn from storage at request of United Electric, 7¢ per ton will be charged for such withdrawal.

Previous contract provided for re-opening of price and annual tonnage each year and this new contract gives firm commitment on price and tonnage.

NOW, THEREFORE, BE IT RESOLVED, that the action of the officers of this Company, for and on its behalf, in entering into such contract with Central Illinois Light Company, upon the terms and conditions as set forth above, be and the same hereby is in all respects approved, ratified and confirmed.

Mr. Hepburn was invited into the meeting and he and Mr. Nugent made a report on the Company's stripping reserves, using maps of Fulton County and Perry County, showing the Company's reserve areas in relation to the reserve areas of other strip companies, and it has been determined that the present reserves provide tonnage for continuing and growing production for about fifteen to twenty years. After discussion, upon motion duly made by Mr. Nugent, and duly seconded by Mr. Thorson, it was unanimously

RESOLVED, that the proper officers of this Company, for and on its behalf, be and they hereby are authorized and directed to begin at once an aggressive program to option for purchase and/or lease areas for test drilling in the North Canton and South Buckheart areas in Fulton County, and in the area in Perry County and Jackson County immediately south of the property acquired from Union Colliery Company.

The President reported to the Board that the new Bucyrus-Erie 70-yard stripping shovel was expected to be delivered and in operation at Fidelity Mine sometime late in the current year. This machine was

EXCERPT FROM MINUTES OF MEETING ON SEPTEMBER 8, 1961

The Chairman recalled that at a meeting of the Board held on July 14, 1961, a resolution was adopted authorizing the sale of a tract of 174 acres at Mary Moore Mine, said authorization subject to appraised value being obtained. The President then reported that an appraisal was obtained from a bank in Danville, Illinois, the value being set at $50,000 cash, or possibly $70,000 if sold by contract. Another appraisal was obtained from a Peoria appraisal firm which established the market value at $65,000. Since the price offered by the prospective purchaser, Niels C. Nielsen, was $85,000, the sale will be made to him, the purchase price to be paid as follows: $25,000 on signing of contract, $20,000 on each of the three next successive anniversaries, with interest on the unpaid balance at 5% per annum. However, Mr. Nielsen has agreed to purchase certain small tracts adjacent to the 174 acres that will eliminate the need for the Company to remove a haulage road and construct a private bridge, thus saving the Company an estimated $12,000 to $15,000, and consummation of the sale is contingent on Mr. Nielsen so doing.

In regard to the annual report for the fiscal year ended July 31, 1961, a draft of the letter to stockholders and a review of the results were read. It was pointed out by the President that in previous years only the coal deposits suitable for strip mining were included in our annual report. After considerable discussion it was decided that total coal deposits, both strip and underground, owned and controlled by the Company be shown in the annual report.

Upon motion duly made by Mr. Nugent, and duly seconded by Mr. Thorson, the following preamble and resolution were unanimously adopted:

> WHEREAS, the proper officers of this Company expended certain sums for equipment for use at its various mines as follows:

EXCERPT FROM UEC BD. MEETING - SP. MTG. MAY 18, 1962

and

WHEREAS, the resolutions authorizing and/or approving said coal mining leases did not state that the acquisition of minerals included also "the right to use the surface" for such purposes as may be necessary in carrying on the strip mining operations; and

WHEREAS, such right is included in the coal mining leases;

NOW, THEREFORE, BE IT RESOLVED, that the wording of the resolutions authorizing and/or approving the six coal mining leases cited in the foregoing preamble should include the phrase "the right to use the surface", and that said phrase be and the same is hereby made a part of each of the cited resolutions the same as if it had been included in the original resolutions.

Mr. Nugent, Chairman of the Land Committee, referred to the coal land reserve position of the Company and the need to add to the operating life of present mines. The Company should continue to pursue a vigorous land acquisition program, not only at existing properties but at any location that might provide additional reserves and extension of mining activities. Management was again instructed to pursue this policy in acquiring additional coal lands suitable either for strip or underground mining.

Upon motion duly made by Mr. Crown, and duly seconded by Mr. Nugent, the following preamble and resolution were unanimously adopted:

WHEREAS, the proper officers of this Company expended the sum of $66,331.20 for the purchase of 1 Northwest 80-D coal loading shovel for use at Banner Mine;

NOW, THEREFORE, BE IT RESOLVED, that the action of the officers of this Company, for and on its behalf, in expending the sum of $66,331.20 for equipment as set forth above, be and the same hereby is in all respects approved, ratified and confirmed.

The Chairman advised that Midcontinent Barge Company, which Company is owned jointly with Truax-Traer Coal Company, desired to

purchase six 1,500 ton barges to take care of the increase in coal shipments on the Mississippi River. The Chairman further stated that Ingalls Ship Building Company has for sale six new barges, just recently completed, and of the type now in use by Midcontinent Barge Company. The purchase price of the Ingalls' barges is $60,000 per barge as compared with $61,500 and $63,900 per barge quoted by two other builders, neither of which could make immediate delivery.

At a meeting held on May 15, 1962, the Executive Committee authorized this Company, as a stockholder in Midcontinent Barge Company, to approve the purchase of the six barges, and that this Company purchase 1,000 shares of the no par value capital stock of the Barge Company for $150,000, the proceeds of such stock to be used toward completion of such purchase of barges. The 1,000 shares would continue to represent this Company's 50% share of the capital stock of such Barge Company.

After discussion, on motion duly made by Mr. Ames, and duly seconded by Mr. Thorson, the following preambles and resolution were unanimously adopted:

> WHEREAS, the Executive Committee of the Board of Directors of this Company at a meeting held on May 15, 1962, authorized the purchase of 1,000 shares of Midcontinent Barge Company's no par value capital stock, being the allocable portion of this Company's interest in such Barge Company, at a price of $150,000, on the determination that such $150,000, together with other available monies, will be used to purchase six 1,500 ton capacity barges by Midcontinent Barge Company, and also approved the authorization by this Company of making such purchase of barges; and
>
> WHEREAS, Midcontinent Barge Company has authorized the issuance of such shares to this Company; and
>
> WHEREAS, the Continental Illinois National Bank and Trust Company of Chicago and The Chase Manhattan Bank have agreed in writing that the expenditure of such money for the purchase of stock of Midcontinent Barge

EXCERPT FROM MINUTES OF MEETING ON JULY 13, 1962

The Chairman then presented a resolution approving this Company's action in signing a coal lease with United States Steel Corporation under which the life of Mary Moore Mine would be extended some four years.

After discussion, upon motion duly made by Mr. Crown, and duly seconded by Mr. Thorson, the following preamble and resolution were unanimously adopted:

WHEREAS, the proper officers of this Company on June 28, 1962 entered into a lease with United States Steel Corporation covering the acquisition of all of the coal of the #7 vein and the right to mine the same on approximately 111 acres in Vermilion County, Illinois, containing an estimated 645,000 tons of the #7 vein, the consideration being 15¢ per ton royalty with minimum royalty of $60,000, payable $6,000 on January 10, 1963 and $6,000 per year on each of the succeeding nine anniversary dates;

NOW, THEREFORE, BE IT RESOLVED, that the action of the officers of this Company, for and on its behalf, in entering into the coal lease with United States Steel Corporation, upon the terms and conditions as set forth above, be and the same hereby is in all respects approved, ratified and confirmed.

Upon motion duly made by Mr. Crown, and duly seconded by Mr. Thorson, the following preambles and resolution were unanimously adopted:

WHEREAS, the proper officers of this Company on June 28, 1962 entered into a lease with United States Steel Corporation under the terms of which this Company acquired the right to mine all of the coal contained in the #7 vein on certain premises in Vermilion County, Illinois; and

WHEREAS, Karl Zamberletti and Frances Zamberletti, co-partners doing business as V-Day Coal Company, on October 14, 1960 entered into a lease with United States Steel Corporation under the terms of which V-Day Coal Company acquired the right to mine all of the coal contained in the #6 vein on certain premises in Vermilion County, Illinois; and

WHEREAS, the premises containing the #6 vein leased to V-Day Coal Company are identical with the premises containing the #7 vein leased to this Company; and

WHEREAS, the #6 vein underlies the #7 vein, being separated from same by some 40 feet; and

4196

EXCERPT FROM UEC BD. MEETING MARCH 8, 1963

WHEREAS, Midwest Towing Co. Inc., owned jointly by this Company and another coal company, experienced a decrease in revenue received from its winter operations on the Ohio River largely because of bad weather and inoperable river conditions; and

WHEREAS, Midwest Towing Co. Inc. needs working capital to operate on the Mississippi River during the summer months;

NOW, THEREFORE, BE IT RESOLVED, that the proper officers of this Company be and they hereby are authorized to lend to Midwest Towing Co. Inc. an amount not to exceed $75,000 for a period of three months, secured by a promissory note executed by the proper officers of Midwest Towing Co. Inc.;

FURTHER RESOLVED, that should the amount lent to Midwest Towing Co. Inc. exceed $50,000, approval to make such loan will be obtained from the Continental Illinois National Bank and Trust Company of Chicago, representing the lending banks under this Company's loan agreement dated September 1, 1961.

Opening a general discussion on the question of mineable reserves the President stated that at Buckheart the total possible including present operating area, North Canton and South Buckheart would amount to some 46,600,000 tons, most of which have been acquired or optioned. At Cuba Mine possibly 1,500,000 tons of #6 are available although not yet acquired; possibly 3,500,000 to 5,000,000 tons of #2, some of which is under option, and all of which is high ratio stripping; making a possible estimated total of 7,000,000 or 8,000,000 tons for the Cuba plant.

In the northwest part of Fidelity field there are some estimated 4,000,000 additional tons that will be added, bringing the estimated total to about 28,000,000 tons.

In the face of the obvious limits in strip tonnage available in the vicinity of the Company's properties now being mined a study is being undertaken to determine as nearly as possible all of the strippable reserves in Illinois, Indiana, West Kentucky and Missouri, and by what method such reserves can be acquired.

and arrangements have been made to do this.

After discussion, upon motion duly made by Mr. Gebhart, and duly seconded by Mr. Falkoff, the following preamble and resolution were unanimously adopted:

> WHEREAS, this Company plans to purchase from Truax-Traer Coal Company approximately 83 acres of land in Perry County, Illinois, containing an estimated 600,000 tons of coal, the total consideration being $16,191.05;
>
> NOW, THEREFORE, BE IT RESOLVED, that the proper officers of this Company, for and on its behalf, be and they hereby are authorized and directed to purchase said tract from Truax-Traer Coal Company, upon the terms as set forth above.

The Chairman reported on the Company's activities in acquiring stripping reserves in Colorado. On prospecting permits acquired from the Federal Government preliminary drilling indicates some 18,000,000 tons of strippable coal with perhaps additional tonnage available when a more complete drilling program is undertaken. This tonnage is located in Routt County near Haydon where Colorado Ute Electric Association is building a steam generating plant, the initial capacity to be 225 megawatts with additional units being planned for future expansion. This Company is also attempting to acquire both strip and underground reserves in west central Colorado near Grand Junction where the Public Service Company of Colorado operates a steam generating plant.

In Illinois this Company's reserves increased 5,000,000 tons over production for the year ended July 31, 1963.

The proposed President's letter and a report (Review of the Year) for the annual report for the year ended July 31, 1963, were discussed and approved as to substance as drafted.

The Chairman then stated that the next order of business was

BOARD OF DIRECTORS MEETING HELD MAY 8, 1964

The Chairman informed the Board that the Company had acquired an option to purchase 372 acres of land in McDonough and Schuyler Counties, Illinois (Industry Field) at a price of $170 per acre containing an estimated 600,000 tons of strippable coal. It was brought out in discussion that recent changes in transportation costs and improvement in underground mining cost place the Industry Field in a somewhat doubtful position in planning a stripping development on this acreage. Land acquisitions in this area have been limited to purchases or leases which can be made at approximately farmland prices. The land in question is adjacent to the other acreage that makes up the main body of the Industry Field and will fit into any future requirements for development. The area is being actively farmed and pastured by the Company at present.

After the above discussion, upon motion duly made by Mr. Nugent and duly seconded by Mr. Thorson, the following preamble and resolution were unanimously adopted:

> WHEREAS, the proper officers of this Company on December 2, 1963 entered into an Option with Contract to Purchase with John C. Stoneking and Bessie M. Stoneking, covering the purchase of approximately 372 acres of land in McDonough and Schuyler Counties, Illinois (Industry Field), containing an estimated 600,000 tons of coal, at a price of $63,240.00, payable $240.00 on execution of contract, and $9,000.00 per year for seven years, which agreement contains the usual provision that this Company may terminate it at any time by forfeiture of the payments previously made;
>
> NOW, THEREFORE, BE IT RESOLVED, that the proper officers of this Company, for and on its behalf, be and they hereby are authorized and directed to exercise said option with John C. Stoneking and Bessie M. Stoneking upon the terms and conditions as set forth above.

EXCERPT FROM UEC BOARD MEETING AUGUST 12, 1966

Mr. Morris outlined the need for additional stripping equipment at the Fidelity Mine. Present equipment will maintain current production rate in the present pit for approximately eighteen months, at which time, with deeper overburden, the 1650-B would need help to maintain production of approximately 180,000 tons per month.

After mining all of the coal in the present location (Green Pit), the estimated reserves at Fidelity that can be stripped is 23,000,000 tons. This is located in three different areas and shows overburden depths, rock and surface material that would require a machine to help the 1650-B to mine it all out economically. Without a helper, monthly production would be reduced from its current rate of 180,000 tons to approximately 125,000 tons, with resultant cost increase. Also, of this 23,000,000 tons, approximately 10,000,000 could not be mined at all with the one machine (1650-B). The need for additional help is thus established as necessary.

Mr. Morris stated that after thorough investigation, a wheel, properly designed for the particular areas involved, seemed to be the best solution.

The following information and estimates have been developed.

1. Bucyrus-Erie has a standard design and has built a wheel for Peabody and one for Truax. It is high enough for us, but for our purpose certain modifications of design seem necessary. They put a price on their standard dsign of $2,500,000, and an estimate on transportation and erection of $400,000.

While we don't know exactly what the change in design we would need would cost, they have indicated that the engineering and other factors involved would cost somewhere in the neighborhood of another $400,000. So it appears we are thinking about something over $3,000,000 for a Bucyrus machine properly designed and in place, ready to operate.

2. We have built four wheels, three of which are now in operation. The W-2 is at Buckheart, the W-3 at Banner, and the W-4 at Cuba. The W-3 was originally at Fidelity Mine but the design of this particular machine did not properly serve the need at that mine and it was not successful there. It was redesigned and moved to Banner and our cost and profit record there will indicate its satisfactory performance.

   The wheels at both Buckheart and Cuba are doing a satisfactory job.

3. We have all of the engineering information and blue prints necessary to build the type of wheel we need at Fidelity. This is quite a cost saving.

   The machine would be built higher, the digging end longer, and the stacker end some longer and higher to place the dirt back far enough in deep overburden to avoid slides. We would use the base, motors and quite a lot of other material from the 5561 Marion shovel which is now a stand-by at Fidelity.

4. Utilizing our engineering knowledge, blue prints, and experience, and building the machine on the site, would effect considerable savings. The repair parts in inventory for the 5561 and also repair parts in inventory for Wheels 2, 3 and 4 would be available for the W-5 machine.

5. Our estimate of the total cost, using our own people for the engineering and supervision, and contracting for the welding, erection and so forth, is $1,800,000.

   We feel our estimates are within reason and have included in the above figure $200,000 for contingencies and unexpected difficulties.

   In our five-year budget for capital expenditures, we included $250,000 in 1966 and $1,750,000 in 1967.

   We can build this machine and have it in operation within fourteen months. The best estimate from Bucyrus is eighteen months and probably longer.

After discussion, upon motion duly made by Mr. Nugent, and duly seconded by Mr. Thorson, the following resolution was unanimously adopted:

> RESOLVED, that management be authorized to proceed with the necessary purchasing and contractual arrangements to build Wheel No. 5 for use at the Fidelity Mine at a cost of not to exceed $1,800,000.

EXHIBIT "A"

DX 114

THE UNITED ELECTRIC COAL COMPANIES

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS

Notice is hereby given that the Annual Meeting of the Stockholders of The United Electric Coal Companies will be held at the office of the Company, 307 North Michigan Avenue, Chicago, Illinois, on Friday, October 29, 1954, at 10:30 A.M. Central Standard Time, for the purposes of electing a Board of eleven (11) Directors to serve until the next Annual Meeting of Stockholders and until their successors are elected and qualified, and of transacting such other business as may properly come before the Meeting.

The Board of Directors has fixed the close of business on September 29, 1954, as the record date for the determination of stockholders entitled to notice of and to vote at the Meeting.

If you do not expect to be present at the Meeting, please sign and mail the enclosed proxy in the return envelope provided for that purpose. No postage is required if mailed in the United States.

PROXY STATEMENT

1. The Annual Meeting of Stockholders. The Annual Meeting of the Stockholders of the Company will be held on October 29, 1954, pursuant to its By-laws for the purposes of electing a Board of eleven (11) Directors to serve until the next Annual Meeting of Stockholders and until their successors are elected and qualified, and of transacting such other business as may properly come before the Meeting. As of the date of this Proxy Statement the election of Directors is the only matter which the management intends to present or knows will be presented by others. Should any other matter properly come before the Meeting, it is the intention of the proxies named in the enclosed proxy to act upon it according to their best judgment.

2. The Proxy. Proxies in the form which is enclosed with this Notice and Proxy Statement are solicited by and on behalf of the management. When the proxy in such form is properly executed and returned the shares represented thereby will be voted at the Annual Meeting. Any stockholder giving a proxy in such form has the power to revoke it at any time prior to its being voted.

3. Voting Securities and Principal Holders thereof. As of September 29, 1954, the record date for stockholders entitled to notice of and to vote at the Meeting, the Company had 750,000 shares of common stock of $5 par value each authorized, of which 677,920 shares were issued and outstanding. Each stockholder has one vote for each share held. In the election of Directors, the holders of stock do not have cumulative voting rights.

As of July 31, 1954, Material Service Corporation owned beneficially 72,600 shares of common stock of the Company which shares represented approximately 10.7% of the outstanding voting securities of the Company on that date.

CONF-660930

DX 116

nuclear power briefing

for the COAL INDUSTRY

September 29-30, 1966
Oak Ridge, Tennessee

United States Atomic Energy Commission | Division of Technical Information

• • •

Nuclear Fuel Fabrication
by James H. Hill
Vice President, United Nuclear Corporation

It is a pleasure for me to be in Oak Ridge to participate in the nuclear power briefing for the Coal Industry. I notice that Dr. Weinberg is speaking this evening on the subject "Uranium and Coal - Partners or Rivals?". I suspect that he is going to suggest that we should be partners. In any event it is in that spirit that I accepted the invitation to be here.

The purpose of this paper is to present a brief account of the various steps in taking uranium from the earth and converting it into a finished reactor core for the production of central station electrical power. The details involved in "burning" uranium are somewhat more complex in comparison with the burning of coal. However, some of the complexity of the subject can be attributed to the nuclear jargon, mathematical equations, and chemical formulae which are commonly used in the industry. As far as fuel fabrication is concerned I think that it unfolds in fairly simple steps for discussion as follows:

Mining and Milling -
Conversion of U_3O_8 to UF_6
Enrichment of UF_6
Production of UO_2 and Pellets
Fuel Tube Loading - Welding and Assembly
Fuel Management
Market Development for Fuel Fabrication
Price Trends

I will limit my remarks to a brief discussion of each of these steps related to the fabrication of nuclear fuel for commercial power reactors.

Mining and Milling

First the uranium ore must be located, the ore body developed and then mined. A major portion of the mines and mills is located in New Mexico, others are located in Wyoming and Colorado. The ore is usually hauled to the mill in large trucks.

The purpose of the milling operation is to recover the U_3O_8 from the ore. The ore that is being mined today contains about four to five pounds of U_3O_8. The mill that I will describe is designed to process about 3,000 tons of ore per day by the alkaline leach-caustic soda precipitation method.

The first step in the milling operation is the crushing and screening of the ore in a closed circuit to produce a crushed product of less than half an inch in size. Some of the ores are wet and must be put through a rotating kiln-type dryer between the crusher and the screens. Next the ore is introduced into a ball mill grinding and classifier circuit in which it is reduced to the size of extremely fine sand. A slurry and solution of this finely ground ore is pumped to a large tank with slowly moving rakes

in the bottom. The ore slurry settles to the bottom and is t... pumped to a leaching circuit where the uranium goes into solution by reaction with sodium carbonate. The uranium solution is separated from the worthless sands by filtration and is then reacted with sodium hydroxide. It precipitates as U_3O_8 which we call "yellowcake". The "yellowcake" is filtered from the slurry and heated in a furnace. Heating at about 1600°F converts the vanadium in the "yellowcake" to a water soluble compound. The hot material drops into a tank of water and the vanadium dissolves. The vanadium is sold as a by-product. Again the "yellowcake", now free of vanadium and assaying 86% uranium oxide, is filtered, dried, and packed in drums that contain 1,000 pounds of finished product ready for shipment. It takes about 4,000 to 5,000 tons of this material (U_3O_8) to fuel an 800 Mwe reactor over its thirty-year lifetime. The cost of the U_3O_8 is about 27% of the total cost of a reactor core.

Conversion of U_3O_8 to UF_6

The next step in fuel preparation is the conversion of U_3O_8 into UF_6, the feed material for the gaseous diffusion enrichment plants. Two conversion processes have been in general use in this country. The process used in the Government plants involves the removal of impurities from the U_3O_8 in nitric acid solution by an organic solvent extraction process. The resultant uranium oxide is hydrofluorinated and converted to a green powder called uranium tetrafluoride (UF_4) -- additional treatment with fluorine converts it to UF_6. The second method, used in industry, is more direct. It eliminates the solvent extraction step and carries the impurities through to the UF_6 phase where they are removed by distillation.

The Government UF_6 plants and the Allied Chemical Company's UF_6 plant at Metropolis, Illinois have been shut down for over two years. Allied indicated recently that it is ready to resume operation. I expect that within the next few years other companies will participate in the business of converting U_3O_8 to UF_6.

The cost of conversion of U_3O_8 to UF_6 is about 5% of the total cost of a reactor core.

Enrichment of UF_6

After the U_3O_8 is converted to UF_6, it is shipped to one of the Government's three gaseous diffusion plants for enrichment. The natural uranium in the UF_6 feed contains 0.711% uranium-235, the fissionable isotope. It has to be enriched to about 3% for use in the types of reactors that are being built today.

Prior to 1964, enriched uranium could be owned only by the Government but it could be leased at 4-3/4% interest for private licensed uses. Since the passage of the Private Ownership Act of 1964, it can be either purchased or leased. The purchase price is based on full recovery of Government costs -- $8 per pound for U_3O_8 and $30 per kg unit of separative work in the enrichment service. Beginning in 1969, it will be possible to produce or purchase U_3O_8 at competitive prices, convert it to UF_6 and have

it enriched in the Government's plant by paying the \$30/kg separative unit tolling charge.

Two products emerge from the diffusion plant. One with an increased content of fissionable material and one with a decreased content. The enriched material is the fuel; the depleted material is called "tails". The owner of the material will have the option of giving up title to the depleted material or of taking it by paying handling and shipping charges. Someday these tails probably will be valuable as fuel for breeder reactors but today they have little value.

The cost of enrichment is about 32% of the total cost of a reactor core.

Production of UO_2 and Pellets

The next step in nuclear fuel fabrication is to convert the enriched UF_6 into the proper chemical and physical form required in the final reactor core. Pressurized Water Reactors (PWR) and Boiling Water Reactors (BWR) require about the same amount of basic fuel material (U_3O_8) per megawatt of capacity over a thirty-year plant life. Both are fueled with pellets of UO_2 and now the trend is for both to use zirconium fuel tubes. There the similarity in fuel ends. A typical high power PWR uses an initial loading of about 220,000 pounds of UO_2 pellets that are about .30 inch in diameter. A typical high power BWR uses an initial loading of about 360,000 pounds of UO_2 pellets that are about .50 inch in diameter. The initial loading for the BWR is larger than the PWR because the enrichment is lower. However, the PWR requires the production of about twice as many pellets per pound of UO_2 because of the difference in pellet diameter.

The chemical and physical operations required in the production of UO_2 pellets are complicated only by restrictions on equipment and procedures imposed by criticality and health physics considerations.

The conversion of enriched UF_6 to UO_2 is generally accomplished by either the "ammonium diuranate" (ADU) process or by the "organic reduction" process. The differences in these two processes occur primarily in their first steps in converting UF_6 into a stable solid compound suitable for further processing.

In the "ADU" process gaseous UF_6 is introduced into a solution of ammonium hydroxide. This forms a stable solid compound, ammonium diuranate. The ADU is separated by filtration and dried, then converted to UO_2 powder by heating to red heat in the presence of steam and hydrogen.

The "organic reduction" process begins with introduction of gaseous UF_6 into a vessel containing an organic reducing agent. The UF_6 is converted to UF_4, a stable compound commonly known as greensalt. The UF_4 is then converted to UO_2 powder by a reaction with steam and hydrogen.

The UO_2 prepared by either of these processes is in the correct chemical form for reactor use but is much too bulky. To reduce the bulk,

it is pressed into cylindrical pellets. Normally a press feed preparation step is required to give the bulky UO_2 powder better flow characteristics prior to entry into the die cavity of the press. This step produces a granular feed by means of agglomerating the powder with a wax binder. After pressing, the pellets are sintered in high temperature furnaces to form a high density ceramic body. The sintered pellets are then centerless-ground to obtain a finished diameter to a $\pm$ 5/10,000 of an inch specification and are made up into stacks for loading into fuel tubes.

Fuel Tube Loading - Welding and Assembly

The loading of pellets into zirconium tubes is a rather straight-forward operation. The zirconium tubes are about 144 inches long. A large power reactor requires about 450,000 feet or 85 miles of tubes or between 40,000 and 75,000 pounds of zirconium depending upon tube wall thickness.

After the pellets are loaded in the tubes, end caps are welded to seal the pellets inside the tubes in an inert atmosphere. At this point we refer to the product as fuel rods. It takes about 35,000 to 40,000 fuel rods per reactor core for a large plant. The fuel rods are assembled into bundles with appropriate spacers and structures for holding them in a fixed position within the reactor core. An individual fuel assembly for a BWR will contain about 49 fuel rods. An assembly for a PWR will contain about 225 rods. In the BWR the fuel assembly is enclosed in a zirconium can or shroud to accommodate cruciform-type control rods which fit in between each group of four assemblies. The PWR does not use a shroud and present design incorporates control rods in place of fuel rods in selected positions in the assembly. The control rods in both types are needed to regulate the rate of energy production.

The fuel assemblies and control rods combined form the complete reactor core. When the core is placed in the reactor pressure vessel, similar in principle to placing an immersion heater in a teapot, you have "instant" power available -- all you have to do is add water. When the control rods are withdrawn nuclear fission begins (the uranium-235 is "burned") and heat is created which produces steam to drive the turbine-generator system which produces electrical power.

The fabrication cost component, which includes the cost of the zirconium tubes and the production of UO_2 powder and pellets, represents about 36% of the total cost of a reactor core.

Fuel Management

The objective of fuel management is to achieve safe operation and minimum power generation costs. Once the reactor core design has been established fuel management begins. The finished fuel assemblies are checked to verify that the quantities and distribution of uranium-235 meet design specifications. This provides a "bench mark" for subsequent calculations and operational instructions specifying the exact positions or withdrawal patterns in which the control rods should be operated. The maximum power peak position in the core is calculated as a function of control rod position. This is compared with the maximum heat flux that can be tolerated.

The control rod pattern is programmed so that maximum power removal can be achieved without damaging the fuel rods. Power distribution calculations are made on a continuing basis to maintain a precise record of how much enriched uranium has been "burned" in each fuel element and how much plutonium has been produced. The fuel managers thus can identify which fuel assemblies should be removed for reprocessing and the proper location for the addition of new fuel. This type of information supports the selection of a refueling scheme or change in design to yield maximum "burning" of the fuel consistent with minimum fuel cycle costs.

Market Development for Fuel Fabrication

Some special problems face the fuel fabricators and electrical utilities in the replacement core aspect of the business. The utility industry has recognized the need for obtaining competition for its fuel supplies. In the beginning utilities purchased one or two cores from the nuclear power plant manufacturer, with options for future reloads. This did not assure competition on future fuel supply. It is in the nature of reactor core performance, however, that the calculated data and data obtained during operation have to be carefully reviewed and assimilated in order to provide a reasonable set of specifications on which a fuel supplier can bid. Unless the utility company obtains these data, competitive fuel suppliers are placed at a severe disadvantage.

One of the ways utilities can assure competition is to take steps during the initial contract negotiations to insure the availability of sufficient drawings, specifications, operational and performance data to permit competitive bidding on future fuel supplies. If the utility company desires firm warranties for future fuel loadings, then detailed drawings, including materials, dimensions and tolerances, especially as they relate to mating with existing reactor or plant components such as grid structures, handling tools, etc., should also be provided. The detailed operating history of the original fuel and control rods, including burnups, isotopic compositions, power patterns, etc., should be made available to permit the competitive fuel supplier to predict performance of his fuel as related to the initial fuel remaining in the reactor. Water chemistry, corrosion data on materials in the coolant circuit, and thermal-hydraulic performance of existing fuel are also necessary to assure compatibility with replacement fuel.

By effectively requiring this type of information, utilities will be in a position to obtain competitive bidding for replacement fuel from companies other than the initial reactor supplier during the life of the plant. Perhaps an easier way that utilities could assure competition for replacement cores would be to require the reactor manufacturer to procure the equivalent of a reload batch of its initial fuel assemblies under subcontract to a fuel fabricator.

Price Trends

I have taken the liberty of discussing some of the problems that are being encountered by utilities and the nuclear industry as the market develops. I realize that through all of this the subject in which you are

most interested is the future price trend of nuclear power. Only from that can you better appraise the competition that the coal industry faces from nuclear power.

Beginning with the announcement in 1963 that the Jersey Central power plant at Oyster Creek would be nuclear, the electrical utilities have contracted for about 19,000 Mwe installed nuclear capacity in 27 plants. They have announced plans for an additional 6,500 Mwe in 9 plants for a total of about 25,500 Mwe. This does not include the nuclear capacity of about 1,400 Mwe in 15 plants announced, in operation or under construction prior to 1963, nor does it include the prospects for an additional 11 plants expected to be announced within the next year with an additional capacity of about 7,000 Mwe. By 1970 over 11,000 Mwe will be in operation increasing to about 50,000 Mwe in 1975 and to more than 100,000 Mwe by 1980. At that point one out of three new plants may be nuclear.

Some predict that fuel cycle costs will decrease from around two mills per kilowatt-hour for plants operating in 1970 to one mill per kilowatt-hour in 1980. Assuming that the average cost of fuel is 1.5 mills per kilowatt-hour over the thirty-year life of the large plants announced since 1963, the total fuel cycle cost over the life of these plants would be about $8.0 billion. Assuming an initial capital cost of installation of $110 per kilowatt the fuel cycle cost over the life of the plant is almost three times the initial capital cost.

This serves to illustrate two important points. The incentive for further reducing fuel cycle costs by new developments, and the incentive for effective competition in that portion of the business that is really big -- fuel replacement.

It is difficult to predict price trends because of the many variables involved. New processes are under development in industry to produce UO_2 powder with consistent characteristics at reduced costs. Further automation in the production and handling of pellets will reduce costs. The most significant accomplishment in reducing fabrication costs will be the development of a process for obtaining an acceptable fuel element by loading UO_2 powder directly into the fuel tube by vibratory compaction or some other method to avoid the production and handling of the millions of UO_2 pellets required in a core.

An important area for decreases in fuel cycle cost is in the improvement in "burnup" or power generating lifetime of the fuel. The extent of "burnup" is not basically limited by materials because there are design alternatives to solve some of the problems, such as swelling of the fuel due to buildup of fission product gases. The basic limitation is in the control of reactivity of the core and its relation to overall economics. In other words, to achieve longer lifetime and more efficient use of the fuel, considerably more enriched uranium must be added to the core than is necessary to sustain operation in the initial stages. This excess uranium is controlled by adding a burnable poison such as boron. Thus a larger inventory of enriched uranium would have to be financed throughout the entire operation. An economic balance has to be struck between this added cost of financing and the reduction in cost due to longer life of the fuel.

When we start recycling plutonium in replacement cores, this problem will be alleviated to some extent because the plutonium will contain up to 20% plutonium-240. This is an isotope that serves as a poison, similar to boron, in the early life of the reactor by absorbing neutrons. It not only burns out as a poison but converts to plutonium-241, a fissionable isotope which in effect replaces fuel "in situ". I think burnup can be increased by several thousand megawatt days per ton with a decrease in power cost of around 0.1-0.2 mills per kilowatt hour. This could mean a reduction in fuel cost of about $40 million over the life of a 1,000 Mwe plant. Of course the improvement in materials and techniques to permit achieving higher power densities and higher heat flux rates will have a great influence on reducing fuel cost.

The price of U_3O_8 could vary from $6 to $8 per pound up to 1980 without significantly affecting the cost of power. A change in the cost of U_3O_8 by $1 per pound would change the cost of power by about .07 mills per kilowatt-hour. A change of $4 per kilogram separative unit cost in enrichment service would also result in a change in the cost of power of about .07 mills per kilowatt-hour.

The price for the conversion of U_3O_8 to UF_6 was recently reduced by Allied Chemical from $1.25 to $1.04 per pound. With the market that is expected in the early 1970's and the building of competitive plants, one could expect that the price for conversion could be reduced considerably.

I am pleased to have had the opportunity to talk to you and I am sure that representatives from other segments of the nuclear industry will be glad to discuss the subject with you and I will try to answer any questions that you may have.

WASTE BYPRODUCT PRODUCTION *

R. E. Blanco
Oak Ridge National Laboratory

(Presented at the Nuclear Power Briefing for the Coal Industry, September 29-30, 1966, Oak Ridge, Tennessee.)

This afternoon I will summarize the status of the nuclear by-product disposal problem, or as it is more commonly called, the nuclear waste disposal problem and attempt to indicate the proba- course of future developments. It has been said that a safe and economical solution to this proble- must be found if nuclear power is to be successful. Actually, the importance of this problem is the result of the hazardous nature of these wastes rather than the cost of the operations since our studies predict that the cost of waste treatment will be only a small part of the total cost of nuclear power. In short, "We must ensure that these hazardous wastes are permanently isolated from the human environment by some practical method."

(1) Origin and magnitude of problem.

(2) Present treatment methods.

(3) Development of new treatment methods.

SLIDE 1. Origin of Wastes (66-680)

(a) Previous speaker described the recovery of unused thorium, plutonium, and uranium as products from the processing plant. The radioactive fission products are also produced as nuclear by-products.

(b) The radio-isotopes are true by-products if used by industry, but they are waste products if they serve no useful purpose.

(c) Three wastes types:

(a) Aqueous high level, intermediate level, and low level.
Stored in tanks or purified and discharged.

*Research sponsored by the U.S. Atomic Energy Commission under contract with the Union Carbide Corporation.

(b) Solid wastes are buried.

(c) Gaseous wastes are filtered to remove all radioactive particles and discharged up a stack. The air surrounding the stack meets all Federal requirements regarding radioactivity content.

(d) Radioisotopes can be recovered for use by industry as waste by-products. However, we do not predict that the cost of waste treatment will be decreased significantly by the sale of isotopes. We are not sure that the market will ever absorb all of the radioisotopes produced in the power industry.

(e) The other radioactive products serve no useful purpose and are called radioactive wastes.

(f) Liquid wastes are the greatest problem since they contain essentially all of the radioactive products.

SLIDE 2. Waste Management Program (65-11621)

(a) High Level

(1) High salt; 99.99% of fission products; relatively low volumes; now —> tanks; future —> solidify —> salt mine.

(b) Intermediate Level

(1) High salt; <0.01% fission products; relatively low volumes; now —> tanks or bury in concrete. Future —> bury in asphalt or inject as slurry of concrete into deep shale formations. We hope to minimize the volumes of this type of waste through improved processes.

(c) Low Level

(1) Low salt; just water with trace of radioactivity.

(2) Treatment and discharge. Present:

(a) Chemical flocculation.

(b) Ion exchange.

(c) Distillation.

(3) In large plants, chemical treatment cheaper than distillation:

$<1-6/1000 gal vs $15-100/1000 gal.

(d) Remaining discussion on high and intermediate level wastes only, since they constitute the major problem.

SLIDE 3. Approximate Volumes of Wastes and Fraction of Cost (66-640)

Not intended as a precise calculation; used only to show approximate distribution of costs.

(a) Note volume increase from High Level to Intermediate Level to Low Level.

(b) With mechanical decladding, small IL waste.

~110 gal/ton

Buried

(c) Relative importance of HLW is apparent. Recently much research and development work concentrated in this area.

SLIDE 4. Estimate of Waste Conditions in Year 2000 (66-1279)

(a) Estimate as of March 1966 based on AEC estimate in March 1965.

(b) Estimate is now being revised, but illustrates magnitude of the problem.

(c) Shows 31 million gallon of HLW in year 2000.

(d) More than 70 million gallons now in storage in the U.S. This waste contains much less radioactivity but the two volumes illustrate the magnitude of the problem.

(e) The new waste contains a much higher concentration of radioactivity.

(f) Total radioactivity in year 2000 equal to that from 500,000 tons of radium.

$$\frac{(\sim 5 \times 10^{11} \text{ total curies})}{(454) \qquad (2000)} = \frac{5 \times 10^{11}}{1 \times 10^{6}} = 500,000$$

(g) Strontium 90 would be equivalent to 8,600 tons of radium.

(h) Total curies = greater than 5×10^{11} in year 2000.

~130,000 curies/gal after one year cooling

~7,000 curies/gal after 30 years cooling.

SLIDE 5. Present Methods for High Level and Intermediate Level (Photo 46189)

(a) All high level waste in the world is stored in tanks at the present time.

(b) Slide shows Savannah River storage tank.

(c) Contains: cooling coils

3 lines of containment (2 mild steel, one concrete)

(d) One million gallon tank costs about $1.5 million.

(e) Nuclear Fuel Services Co. tanks are ~700,000 gal.

SLIDE 6. Waste Storage Facility (Photo 46190)

(a) Facilities are complicated.

Future Methods

Some years ago under the sponsorship of the AEC, we conducted an extensive survey at ORNL to devise the safest possible treatment and storage method for high level wastes. The safest practical method that we could think of was to convert the waste to solids, preferably extremely insoluble solids, such as a glassy material, and then store it in a place where it would be isolated from water forever; for example, a salt mine where there has been no water for thousands of years. The insolubility of the solid waste would provide extra safety during the interim storage and shipment periods. The question was, "Was this system practical and economical?" We have pursued a development and economic evaluation program to answer the question.

SLIDE 7. Management of High Level Wastes (72614-R3)

(a) Shows overall program.

(b) Economic evaluation of each step.

(c) Granite vaults 2 times more expensive and concrete vaults 5-7 times more expensive than salt.

(d) AEC also sponsored programs at ORNL, BNL, and Hanford Battelle's Northwest Laboratory to develop solidification methods.

(e) Work is being carried out at ORNL to determine the feasibility of storage in salt.

The remaining slides will summarize these studies.

SLIDE 8. Relative Volumes of Wastes from Purex Process (Photo 48506-C)

(a) Relative volumes.

(b) About factor 10 reduction from liquid to solids.

(c) What is the safety and economic advantages of conversion to solids?

SLIDE 9. Conversion of Waste to Glass (Photo 53673-C)

(a) Typifies the conversion step.

(b) Could also just evaporate to dryness and calcine to [illegible]00°C.

(c) These are the bases for the ORNL pot calcination and potglass processes.

(d) Glass has the advantages of high thermal conductivity and extreme insolubility.

SLIDE 10. Flowsheet for Converting Wastes to Solids (Photo 50885R)

SLIDE 11. ORNL Pots (Photo 54842)

(a) Stainless steel, 8 to 24 in.-diam x 8 ft high.

(b) Weld top shut - send to storage.

(c) Fill with glass product or calcine.

(d) One 12-in.-diam pot x 10-ft-long holds 6.08 ft^3 - 15 pots/year of glass would hold all high level waste from a 1000 Mw(e) reactor at 10,000 or 20,000 Mwd/ton.

SLIDE 12. ORNL Hot Pot from Furnace (Photo 59579-C)

SLIDE 13. BNL Continuous Process (CN3-1157-65 BNL Color Photo)

(a) Evaporator to remove liquid.

(b) Flows to a continuous platinum melter to form glass product.

(c) Glass product flows to pot receiver.

SLIDE 14. Hanford Spray Calciner (LR-Dwg. 53279)

(a) Spray dried.

(b) Melted to glass in continuous platinum melter.

(c) Flows to pot receiver.

These three new solidification processes will be tested with radioactive waste in a new pilot plant at Hanford's Battelle Northwest Laboratory. Radioactive tests are expected to start late in 1966.

SLIDE 15. Waste Carrier (Photo 80765)

(a) Experimental carrier is 4 ft diam and weighs 30 tons (35 ton limit by road).

(b) Required carrier for 30 year old fuel, 5 ft diam - holds 36 - 6-in. diam x 10 ft pots, weighs 50 tons - shipped by rail - air cooled by convection - 6-in. to 8-in. thick lead shielding.

SLIDE 16. Salt Mine Storage Facility (63-239R or Color slide 61622)

(a) Experimental unit; old mine at Lyons, Kansas. Leased by AEC.

(b) Easily and cheaply mined.

(c) Many old mines available; 1000 feet down.

(d) Salt beds widely distributed.

(e) Represents ultimate disposal with minimum or no future long term surveillance.

(f) No water; automatic sealing by salt plastic flow.

SLIDE 17. Carrier in Salt Mine (Photo 80977)

SLIDE 18. Experimental Pots in Salt (Photo 80997)

SLIDE 19. Salt Corridor (Photo 81000)

SLIDE 20. Waste Management Data for Conversion to Solids (66-1280)

(a) 34,000 ft^3/year in year 2000.

(b) 310,000 ft^2 total in year 2000. $\approx$ 2.3 million gal vs 31 million gal predicted if it remained as liquid.

(c) Need 3,420 ft of 48-ft-wide canals.

(d) Need 2.1 acres in year 2000 but have committed 1,185 acres of salt.

SLIDE 21. Costs for Storage (65-11624)

(a) Uranium at 10,000 Mwd/ton.
Thorium at 20,000

(b) New tank each 50 years.

(c) Interest rate 4%: present worth financing.

(d) Within limits of these estimates, costs are the same. Therefore, we feel that we are justified in recommending fixation in glass or calcination and storage in salt. This is the safest system that we can conceive of.

(e) Actually, total predicted cost is less than 1% of total cost of 3.5 mill power.

(f) Cost appears to be small but the importance of proving a satisfactory waste disposal method is very great, since, as I said at the beginning, a successful solution to the radioactive waste disposal problem is required if nuclear power is to be successful.

IN SUMMARY

(a) Present treatment methods for wastes, based on tank storage, are adequate, safe, and economical for an interim period.

(b) Improved treatment methods are now under development. As these programs culminate in the next few years we expect to demonstrate significant improvements in safety and economy. At that time, private industry will be able to choose the ultimate disposal system for their use with some certainty.

* * *

URANIUM AND COAL - PARTNERS OR RIVALS?*

Alvin M. Weinberg

The story is told of the hungry lion who was eagerly anticipating a meal of an early Christian martyr. When the Christian was thrown into the arena with the lion, he whispered something into the lion's ear whereupon the lion became deathly pale, trembled all over, and slunk back to his cage. After the Christian was set free he was asked: "What did you say to the lion?" and the answer was: "I told the lion he would be called upon to make an after-dinner speech."

I sympathize on this occasion with the lion. For I am expected, I suppose, to stand before you distinguished representatives of our country's coal industry, who have listened to a day's discussion of just how nuclear energy will put coal out of business, and persuade you that really uranium is coal's best friend. This I cannot do. So to speak, if uranium is coal's best friend, coal doesn't have to look for an enemy. So you will excuse me if I confess that this is an after-dinner speech which at first caused me plenty of indigestion.

Yet on thinking about the matter, I began to relish the job after I decided to speak this evening not as an official spokesman of the Atomic Energy Commission, (which I am not), nor even as the Director of the Oak Ridge National Laboratory, but simply as a former basic scientist who for the past 25 years has been fascinated by the problem of energy. Thus I

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*For presentation before the National Coal Association Meeting in Oak Ridge, September 29, 1966.

shall try to look upon the relation between uranium and coal not from the viewpoint of a proponent of one source of energy, but rather more symmetrically, from the viewpoint of a person who believes that cheap energy is the world's most important resource. With the world's population increasing so rapidly, we shall stave off Malthus only if we can get more and ever more energy. It is my belief that every source of energy will be used in this energy-exploding economy; that each source will eventually find those spheres of use which capitalize on its strengths and minimize its weaknesses; and that the competition between the various sources of energy will tend to keep everyone honest, much to the benefit of the society that must use energy at an increasing rate. I shall therefore try to examine the strengths and the weaknesses of both sources of energy, and to suggest what seem to me to be the major technical problems that each must overcome before it can assume its ultimate and proper niche.

The Strengths and Weaknesses of Nuclear Energy

I begin with nuclear energy: what are its strengths and its weaknesses? Its strengths have been fully expounded today: 1. In large sizes, nuclear electricity appears to be extremely cheap. 2. Because nuclear fuel is compact, the price of nuclear electricity does not depend upon the location of the plant. 3. If breeders are successful, we shall have available an essentially inexhaustible source of energy in the residual uranium and thorium in the earth's crust. 4. Nuclear power plants can be built so as to be almost pollution-free. 5. Finally, nuclear energy is a child of aggressive large-scale research, much of it sponsored by the government, and it continues to profit by the research activities of a vast technical

establishment. Its weaknesses perhaps have not been expounded as fully by the speakers though, judging from the questions put by the NCA, nuclear energy does have weaknesses. I would list them as follows: 1. Nuclear energy is really cheap only in very large size - say 400 MwE and above. 2. Nuclear converters of the present generation burn only a small part of the uranium. Even if more cheap uranium is found, the cost of energy from burner reactors will eventually rise. 3. Though I believe nuclear power plants can be made arbitrarily safe, to do so requires elaborate "engineered" safeguards. How much these must cost to insure beyond any possible doubt against a nuclear catastrophe will always be a matter for argument. In any case, I can understand why so far people are reluctant to place large reactors very close to large cities. 4. Disposal of radioactive waste products from a large nuclear power plant is relatively complicated.

The nuclear community is aggressively capitalizing on its strengths and remedying its weaknesses. You have already heard how the nuclear world is mobilizing around the breeder problem. (Notice that I say breeder, not fast breeder, since I happen to belong to the minority that believes the thermal breeder based on thorium as a raw material is a better long-term bet than is the fast breeder based on uranium.) I might interject at this point my own opinion - that the cheap, safe breeder is one of our society's most important technological goals, and that we ought to be prepared to spend much more on it than we are now doing. In this I believe I agree with many spokesmen of the coal industry. And you have heard of the continuing search for ways to increase the safety of nuclear power plants and to dispose of radioactive residues safely and cheaply. My point

is that the nuclear community understands its strengths and its weaknesses and is mobilized sharply and decisively around them: if breeders are needed, let's get on with their development; if waste disposal is a problem, let's solve it, and so on. And of course in getting on with its job, the nuclear community has two advantages: first, the development of nuclear energy is high national policy and therefore enjoys heavy government support; and second, the industry is dominated by relatively few very large, technically-oriented companies that are accustomed to devoting a sizeable fraction of their income to scientific research and heavy technical development.

The Strengths and Weaknesses of Coal

Let me now list the strengths and weaknesses of coal, as I see them. Its strengths I list as follows: 1. Coal-fired power plants have operated successfully much longer than have nuclear plants. 2. Coal-fired plants, no matter in what size, need no engineered safeguards. 3. Coal's ashes, though troublesome, are far less dangerous than are fission products. 4. Coal-fired plants are cheaper than nuclear plants in the smaller sizes. 5. Coal, in addition to being a source of energy, is a valuable organic chemical and reducing agent: it can be used to reduce iron ore, and it can be converted into liquid fuels, or even into synthetic stockings. Its weaknesses I list as follows: 1. Coal contains noxious pollutants, like sulfur. 2. Coal costs about 20¢/MBtu compared to nuclear fuel, which may cost as little as 5¢/MBtu, and the cost of coal rises sharply with distance from the mine. This redounds strongly to coal's disadvantage in large size plants where the capital cost of the nuclear plant matches that of a coal plant. 3. The coal industry is relatively fragmented, and I suppose I

would say less scientifically oriented than is the heavy electrical equipment industry. 4. Coal, though supported by the Department of the Interior, hardly enjoys as much government support as does nuclear energy.

Having listed the strengths and weaknesses of coal, I shall now go through the list and try to see how the strengths can be capitalized on and the weaknesses eliminated. In so doing I shall try to take the point of view not of a proponent of either atomic energy or of coal, but that of a person concerned in the broadest way with energy in our society.

First, I remind you that the coal industry is in no imminent danger from nuclear fuel. During the past year, more coal was used in the United States than in any year since 1945. The approximately 8,000 Mw of new coal-fired power plants built last year are expected to run for a good 30 years; and with our demand for energy growing, I cannot see a diminishing absolute market for coal. The decision to go coal or go nuclear during the next decade, say, will continue to be a close thing, even in the large sizes where the economics favors nuclear power. In some cases residual doubts that utilities may have about nuclear systems will swing the balance toward coal. These matters will be discussed in more detail tomorrow at the panel on the role of various energy resources, and so I shall not dwell upon them.

The two main technical handicaps coal must overcome if it is to regain its unchallenged position as the fuel for large central stations is first, pollution by SO_2 and other waste products, and second, its relatively high cost of 20¢/MBtu. Let me first consider the second technical question. I ask, are there credible ways of reducing the fuel cycle cost in coal plants?

Two approaches are possible: first, to rationalize further the mining and hauling of coal; and second, to increase the thermal efficiency of coal-burning stations. I'm sure that this audience knows much more about mining and hauling of coal than do I - about the new automatic mining machines being developed by the Joy Manufacturing Company; or the unit-trains; or the coal slurry pipelines which at one time seemed to show so much promise. I can only urge that serious and thoughtful attention to these methods of reducing the fuel cycle cost be encouraged.

I would like to focus on the other, perhaps more promising, possibilities of reducing the fuel cycle cost - by increasing the thermal efficiency. One way which has received great public attention is by means of the magnetohydrodynamic generator - MHD. Again I claim no expertise here, though my instinct somehow makes me rather skeptical: the very high temperatures required in a successful MHD generator pose serious materials questions whose solutions I cannot readily visualize.

Instead I should like to tell you of an interesting possibility that has grown out of the space-reactor work at the Oak Ridge National Laboratory. Mr. A. P. Fraas and his associates of ORNL have examined boiling potassium as a working fluid in a nuclear reactor. Potassium at atmospheric pressure boils at 1,400 degrees F. If it could be used as a topping cycle in a dual system much like the old mercury boiler that ran for so many years in Hartford, Connecticut, one could achieve a thermal efficiency of 55%. At this efficiency, for example, the fuel cost of the Cumberland City coal-fired plant which TVA rejected in favor of the Browns Ferry nuclear plant falls from 1.69 mills/kwh to about 1.20 mills/kwh. This is very close to the fuel cycle cost for the General Electric BWR, and distinctly lower than that of the Westinghouse PWR.

What would have to be done to bring the boiling potassium cycle into being? Obviously a great deal. But we have already operated a small turbine on boiling potassium for 2,500 hours, and there is no obvious reason why a much larger turbine could not be built. The turbine would have to be clad with Nb, as would the tubes of the potassium boiler; and this may turn out to be too expensive. However, I think the possibility deserves some attention, especially since a plant running at 55% thermal efficiency rejects only 55% as much heat to the environment as a plant of the same electrical output running at 40%. In my opinion, the path to 55% efficiency in large central power stations via the potassium turbine appears more credible than the path via magneto-hydrodynamics. If this is a reasonable path to follow, the knowledge created within the Atomic Energy Commission would be extremely useful in achieving the goal.

Let me return to the other technical problem faced by large coal-fired stations: pollution, especially by SO_2. This is a nasty problem which, as I understand it, is costly to eliminate. In this connection I might quote Congressman Chet Holifield, Chairman of the JCAE, who suggested that some of the expertise of the Atomic Energy Commission might be used to help figure out how to reduce the SO_2 effluent from burning coal.

> "If the power industry does not undertake to appraise the present pollution control problem in detail and police itself adequately, someone else - whether it be local, state or federal government - will impose further restrictions upon the industry. It would be far better for the power industry to set its own standards rather than to have restrictions imposed upon it from outside which may be unduly restrictive or unrealistic ...
>
> "The AEC's research and development facilities are second to none. Our objective should be to use them wherever they can be of value. For example, AEC has facilities to sample and measure contaminants in the atmosphere to exceedingly high degrees of accuracy. In addition, AEC has developed methods

of using radiation tracers to study processes such as those involved in the combustion of fossil fuels which will permit the analysis of the complete combustion and effluent process. In this way one could study the best ways of controlling and eliminating certain air pollutants.

"I certainly think the idea of utilizing specialized AEC capabilities for studying the problems of pollution control from fossil fuel plants is worth exploring. The importance of an adequate energy supply for the future goes far beyond a temporary competitive advantage of either nuclear over conventional fuel or vice verse. I am interested as a public servant in advancing the utilization and efficiency of all fuel resources. I believe it would be appropriate for officials of the electric utility industry to confer with responsible officers in the AEC and other executive branch agencies to discuss means of accomplishing this result."*

The Ultimate Place of Coal-Liquid Fuel

One admittedly long-range, though possibly very attractive, way of getting rid of SO_2 would be to liquefy coal, converting it to a crude oil essentially by adding hydrogen to the coal. In the process the sulfur is converted to the volatile H_2S which is eliminated from the final product.

This possibility of eliminating sulfur from coal by liquefaction leads to one of my main points - that in the battle for very large central station power, coal, even with the improvements I have envisioned, will ultimately lose to the most advanced breeder reactors. For example, the molten salt breeder, a pilot version of which you will visit tomorrow, should enjoy fuel cycle costs of about 0.3 mill/kwh. I estimate that such a system in 1,000 MwE size could, under TVA ground rules, produce energy at 1.5 mills/kwhE. Since in this reactor fission products are continuously removed, it has a certain built-in safety; and even if one fuels the reactor with thorium costing $40.00/lb., (there is enough in New Hampshire to meet the demands for many thousands of years), the cost of energy would still be below 2 mills, with TVA financing. In truth, I do not see any

*Nucleonics 24, 18 (July 1966).

possibility of large coal-fired plants meeting this competition which should be raising its head, seriously, in about 15 years.

Under the circumstances it seems to me common sense, and in the interest both of the nation and of the coal industry, for coal to move into a vast and different market: liquid fuel especially for vehicles and organic chemicals. However, since the market in organic chemicals is measured in millions of pounds/year, not millions of tons, I shall concern myself with the possibility of liquid fuels from coal.

The crisis that coal faces - if indeed one can describe as a crisis a situation in which coal still accounts for 24.5% of our energy - will not really take hold for 15 years or so. During that time we shall be mining our crude oil at an increasing rate. The current average price for domestic crude oil is $3.00/bbl., though the range goes from $2.00/bbl. to $3.40/bbl. for normal crude to $4.63/bbl. for high-grade Pennsylvania crude. Even though foreign crudes can be expected to come in at lower prices, I cannot imagine our country ever allowing itself to get in the position where we do not have an adequate domestic crude oil supply. Thus, we shall eventually have to get oil from solid materials - either from coal or from oil shales. When we shall have to do this on a large scale will depend on many factors and will vary from place to place: for example, in South Africa, which aims at self-sufficiency, oil (as well as many petrochemicals) is now produced on a huge scale from coal at the SASOL plant.

Where then do we stand in converting coal into oil - and is there any way in which nuclear energy can help? Basically, the problem in liquefying coal is to add hydrogen to the carbon contained in the coal - to

change C_2H, which is approximately what coal is, to CH, which is roughly the composition of liquid hydrocarbons. The hydrogen for this process can be obtained independently, say by electrolysis of water; or by steam-coal reforming with very high-temperature heat obtained from an outside source; or by steam-coal reforming with heat obtained by burning some of the coal with oxygen. These three processes are summarized in Fig. 1, prepared by C. E. Guthrie of the Oak Ridge National Laboratory. As you can see, the estimated minimum cost of \$2.40/bbl. does not include losses, operating and maintenance costs, taxes, insurance, or profits. Nevertheless, one cannot escape the impression from the figures that liquid fuel from coal ought to become competitive in our country within a generation - roughly at the time when the requirement of coal for fueling central power stations diminishes.

What role can nuclear energy play in this great redeployment of coal? I see two possible roles, though I want to make clear that both of these are rather speculative at present. First, if the molten salt breeder, for example, can produce electrical energy at 1.5 mills/kwh, then we could electrolyze water with this cheap power to extract hydrogen at 20¢/MSCF; this is the source of the price used in the Guthrie Table, Case A. And secondly, if we can get high temperature by heating with electricity at 1.5 mills/kwh, rather than the 2.5 mills/kwh assumed in the figure, we could reduce Guthrie's \$2.40/bbl. to perhaps \$2.20/bbl. Or alternatively, if the high-temperature heat could be obtained from a reactor directly, this would be much more efficient than electric resistance heat, and could be used to advantage for the endothermic steam reforming step in Case B.

I would be doing you a disservice to pretend that I see a clear way for coal to take over the vast market for liquid fuel - either with or

without the help of uranium. But I am convinced that this is a most important direction to investigate thoroughly and seriously, and that the country's scientific resources ought to be deployed massively around this problem.

The Indivisibility of the Problem of Energy

This brings me to my last point. I listed as a weakness in coal's position its relative fragmentation, and its relatively unscientific tradition as compared with oil which is dominated by extremely large companies that are strongly influenced by science. It goes without saying that coal, in order to hasten the arrival of the time when liquefaction is economical, will have to devote more resources to research. Perhaps this will be done entirely within the coal industry - probably more likely through mergers between coal and oil companies, as illustrated by the recent merger of Continental Oil Company and Consolidation Coal Company.

Insofar as the large-scale conversion of coal to liquid hydrocarbons is a matter that touches the national interest, I believe the government should be involved, and involved heavily. To some extent this is already going on: the Bureau of Mines and the Office of Coal Research together have spent 10 to 12 million dollars per year on developing methods for liquefying coal. The AEC has pursued a very high-temperature reactor experiment, the UHTREX at Los Alamos aimed at providing heat for hydrogenation of coal. I would think it reasonable for government to take as seriously as the technology allows the problem of coal liquefaction in all its manifestations: generation of cheap hydrogen via cheap nuclear electricity, new process heat reactors, possibly using boiling potassium as a working fluid.

The rivalry between coal and uranium is good and in the best American tradition. It is good for coal to be put under the kind of economic pressure that forces it to improve mining methods, and come up with unit-trains. It is good for uranium to be asked sharp, no-holds-barred questions such as Mr. O'Brien and his staff at NCA are so good at asking.

But I think there is still something lacking. Nuclear energy has its government champion - the AEC and the JCAE; coal energy has its government champion - the Department of the Interior. I cannot fault either of these two vigorous and well-run agencies. Yet I would raise the question - should there not be some home in government for energy itself - not nuclear, or coal, or oil, or solar, or water - but all forms of energy which, after all, is the ultimate raw material?

That some such feeling must exist in Washington is suggested by the energy study that has been going on for several years in the Office of Science and Technology under the leadership of Ali Cambel, of Northwestern University, and that we are all awaiting. This study will look at the entire energy picture. I should think that the broad responsibility for energy suggested by the outlook of such studies might well become the job of some yet-to-be organized agency.

I realize, that in suggesting that we alter existing government structures, I am treading on the most treacherous political ice. Yet I said at the beginning of my talk that I was speaking not as a representative of AEC nor for that matter of the Department of the Interior for whom ORNL also does work. I speak simply as a person deeply convinced of the increasing role of energy in our society. From this point of view, I believe it to be an important order of business of our government to reexamine its alignment and structure for dealing with the broad problem of

energy. Out of such a reexamination I hope will come a more rational way of coping with our society's ever-growing, and even insatiable, demands for energy, and that the full potentials of both uranium and coal will be exploited for the benefit of all.

* * *

EVALUATING THE COST OF NUCLEAR VERSUS FOSSIL-FUELED POWER PLANTS

Presentation By G. O. Wessenauer, Manager of Power,
Tennessee Valley Authority
At The
Nuclear Power Briefing For The Coal Industry
U. S. Atomic Energy Commission
Oak Ridge, Tennessee
September 30, 1966

Description of the TVA System

TVA supplies the power requirements of the region it serves from the output of 47 hydroelectric plants and 11 steam plants. These generating plants are connected with each other and with the loads they serve by 14,000 miles of high voltage transmission line, including 400 miles of new extra-high-voltage (500-kv) lines. The TVA system has strong interconnections with the major electric systems in adjacent areas. (See Figure 1.)

Load Growth

Rapid growth is a significant characteristic of loads in the TVA region.

Starting in 1933 with 250,000 kilowatts of capacity in the Wilson Hydro Plant and the Wilson Steam Plant, TVA has responded to the region's thirst for power until, today, system capacity exceeds 18 million kilowatts. Of this, about 4 million is hydro and 14 million is steam. (See Figure 2.)

A coal burning unit with 1,150,000 kilowatts is now under construction and designs are under way for two nuclear units of 1,152,000 kilowatts each.

By 1971, when the second nuclear unit is scheduled for service, system capacity is expected to exceed 21 million kilowatts.

TVA's engineers already are anticipating the day when the region's power requirements will reach 50 million kilowatts, and the facilities TVA is building are designed with a 50-million-kilowatt-system in mind.

Load growth is one of the most important factors any electric system considers in deciding the kinds of generating facilities it should install. A combination of large total loads and rapid load growth permits the economies of scale that come from large individual generating units, the concentration in one plant of several such units, and extra-high-voltage transmission.

Large scale operations are especially important in the evaluation of nuclear power plants because the investment cost per kilowatt of capacity and the operating cost per kilowatt-hour decline much more rapidly as size increases for nuclear plants than for plants that burn a fossil fuel.

Economies of scale are so very important that there is a trend toward the pooling of interests among otherwise independent systems, in which two or more systems share the use of facilities that might be too large for the systems individually.

System Economics

The generating capacity available to an electric system must always be greater than its anticipated loads. Reserve generating capacity

is needed so units may be removed from service for scheduled maintenance, and to meet unexpected outages and unexpected load growth.

It may be helpful to our discussion to note something of the way an electric system meets its loads.

Figure 3 shows typical hourly load curves for a week in winter, which is the season of TVA's peak loads, and for a week in spring, which is an off-peak season. On the TVA system, as on all systems, loads vary from hour to hour, from day to day, and from season to season, so that generating units are operated for varying proportions of the time. Some capacity must be operated at all times to meet the minimum loads but some is operated intermittently and for relatively short periods to assist in meeting the peak loads.

Figure 4 is an Annual Load Duration Curve. It is derived by arranging each of the hourly loads in a year from left to right in descending order. The chart has been simplified by drawing a straight line to depict the load duration, when in reality it is a curve. Shown on the chart is the generating capacity used to carry the loads.

The chart shows that about 8 million kilowatts of generating capacity, mostly steam but some hydro, operate 100 percent of the time; roughly 11 million kilowatts, or more, operate about 50 percent of the time; and 14 million kilowatts, or more, operate for shorter periods to meet peak loads.

The load under the duration curve is supplied by the hydro and thermal plants in such a way as to minimize system operating costs. The hydro units, because of their quick starting and stopping ability, are operated the maximum extent possible to utilize the available water for supplying the peak or variable portion of the load. The thermal units with the lowest incremental operating costs are operated the highest percentage of the time and, therefore, are shown supplying the base portion of the load; those with the higher incremental costs operate fewer hours and supply intermediate loads. The highest-cost thermal units operate only during hours of peak load or during emergencies.

The amount of coal burned depends on two elements in this chart: first, the proportion of coal-fired plants that make up the system capacity; and, second, the percentage of time during which the coal-fired plants are operated.

This simplified chart does not show the use of economy and emergency interchange with adjacent electric systems, but TVA does exchange power with other systems, and these exchanges offer significant savings.

TVA's purpose, and the purpose of the neighboring systems with which it interchanges power, is to operate at all times the most economical plants on all systems. In addition to the day-to-day and week-to-week economy exchanges, TVA exchanges large amounts of power seasonally with systems to the south and west.

TVA delivers large blocks of power to them during the summer months which is returned by them to TVA during the winter months. In effect, TVA generates on its own system all of the annual energy required by its annual load.

TVA's large transmission network permits wide flexibility in the choice of generating units to supply the loads. This interchangeability of generation permits use of the most economical power sources to minimize system costs.

Alternatives to Meet Load Growth

Figure 5 is the same load duration curve, except that one year's growth has been added. To show how TVA might use hydro and steam capacity to meet load growth, the portion represented by that growth has been sandwiched between the hydro and steam generation.

What are the alternatives open to TVA in meeting that growth?

Enough additional capacity--in kilowatts--including appropriate reserves, must be added to meet this added peak load as shown along the left edge of the chart; and enough electric energy during the year--in kilowatt-hours--to meet the total energy represented by the load growth band.

There are several ways to provide this capacity. One is to install plants that operate only during peak periods, supplying the bulk of the added energy requirements from existing plants. (See Figure 6) This method can be advantageous if the capacity from the peaking plant has a low capital cost even though it might have a

relatively high operating cost. Peaking capacity can be in the form of hydroelectric projects and various types of fossil-fired generating plants. Some of these plants can be erected at a cost which is only two-thirds to three-fourths the cost of a base-load plant of equal capacity. Since a peaking plant is designed to operate only a small part of the time, the added investment for equipment to gain the extra ounce of efficiency so valuable in a base-load plant is saved. Thus, the incentive is to minimize use of the peaking plant and to increase the use of existing thermal plants.

One type of peaking plant is the pump-storage hydro plant, in which water is pumped uphill to a storage reservoir during off-peak hours for use in driving generators during peak hours. TVA has been considering for some time such a plant that could produce at least a million kilowatts of capacity on peak, (roughly one year's load growth), and modest amounts of energy. To supply the energy portion of the load growth, TVA would have to operate existing coal-fired steam plants a greater portion of the time. Because even the energy attributed on this chart to the pump-storage peaking plant originates in a coal-fired plant, a pump-storage hydro plant would increase coal purchases enough to meet the entire load growth.

Another way to meet load growth is to construct a base-load thermal plant, either coal-fired or nuclear. A new, base-load thermal plant would produce kilowatt-hours at a lower incremental cost than any of the older capacity shown on the chart as operating

less than 100 percent of the time. For that reason, it would operate a high percentage of time, displacing in part generation at the older higher-cost plants so that the amount of energy it produces would be greater than needed to meet load growth alone. Figure 7 shows the total energy that would be produced at a new base-load plant, and the extent to which this generation would replace energy produced at older and higher-cost, coal-fired plants.

The effect of a new thermal, base-load plant on coal purchases will depend, of course, upon whether it is coal-fired or nuclear. If it is coal-fired, system coal burn will increase considerably. To the extent that the new plant burns coal to meet that portion of the load that previously was served by older coal-fired plants, the coal burn may be slightly less due to the better heat rate of the new plant; but the operation of the plant to meet load growth will result in a substantial increase in coal burn. However, if the new, base-load plant is nuclear, coal burn will not only fail to grow as loads grow, but there will be a net reduction in system coal burn.

The decision to build a peaking plant or a base-load plant depends upon which combination leads to the lowest overall costs projected over the life of the new plant. That is, the capital cost of the peaking plant added to the present worth of the operating costs of it and the older coal-fired plants over the life of the peaking plant must be compared to the capital cost of the base-load plant

plus the present worth of its operating costs less the savings in operating costs of the older coal-fired plants.

I would like to emphasize that the factors governing the decision to construct a new plant are different from the factors governing the decision to run that same plant after it is in service. Before a plant is built it must show a lower total cost--including the investment in the plant and transmission, and operating and maintenance expense. But once it is built the plant's relative incremental operating and maintenance expense, which is 85 percent fuel, determines the extent to which the plant is operated.

Nuclear Versus Coal-Fired, Base-Load Unit

Nuclear power plants and coal-fired plants both generate electricity by producing steam to drive turbogenerators. The essential difference between the two is that one uses nuclear fission in supplying the heat to produce the steam and the other burns coal.

A question that continues to be raised is "At what price levels will coal be competitive with nuclear fuel?" This question was reemphasized after General Electric and Westinghouse made their nuclear proposals to TVA, so a review of the evaluation which TVA made may be useful.

Because TVA's evaluation report has been in wide demand, and most of you may have copies, the review will be brief.

TVA's evaluation compares the cost of a coal-fired plant assumed to be located near Cumberland City, Tennessee, which is about 50

miles northwest of Nashville on the Cumberland River, with the cost of a nuclear plant located at Browns Ferry near Decatur, Alabama.

In choosing the most economical location of a coal-fired plant, two important factors are the delivered cost of coal, including the cost of transporting it from the mine to the plant, and the cost of transmitting the power from the plant to the load centers in which the added power supply is needed. A third factor occurs when, as in the TVA area, the lowest cost coal seldom occurs in an area where there is adequate condensing water, so that a mine-mouth plant may require an investment in cooling towers, as at TVA's Paradise Steam Plant. There is adequate condenser cooling water at Cumberland City, and no cooling towers would be needed.

Thus, in locating a coal-fired plant, we seek the lowest combination of (1) the cost of coal, including its transportation; (2) the cost of transmitting power; and (3) the plant investment, including, if needed, the cost of cooling facilities. Because of the importance of the cost of transporting coal, it is desirable to choose a site that can be served by barge, rail, and truck.

In picking a site for a nuclear plant, because the cost of transporting nuclear fuel is relatively small, the distance from the fuel supplier to the plant is a less significant consideration than for coal. The fuel can be chosen through competitive bids from sources that may be widely dispersed geographically. Among the

important variables in siting a nuclear plant are the cost of transmission and the cost of any cooling facilities. Because adequate condensing water is available in widely dispersed sites in the TVA area, a nuclear power plant can be located very close to the loads it will supply, therby holding the cost of transmission facilities to a minimum.

The Cumberland City site offered the best combination of costs for the coal-fired plant to serve the load growth TVA needed to supply. And the Decatur area offered the best site for the nuclear plant. The Browns Ferry site was nearer to where a new source of power was needed in 1970 than the Cumberland City site.

Figure 8 summarizes the main items of the comparisons of the three alternatives. In choosing among alternatives, it is sufficient to measure the cost of energy delivered to the transmission system from the alternatives. Other system costs, involving capacity margins, transmission, marketing, and administrative costs, which are common to each alternative, need not be included. Note that in the comparisons there were some differences in the generating capacities of the three plants. TVA wanted bids on units of about one million kilowatts, but encouraged each manufacturer to choose the most economical unit he could offer in this size range.

The heat rates vary among the three plants from 8,946 Btu/kwh for the coal-fired plant to 10,558 for the boiling water reactor, which is the one TVA chose to build. The heat rate of the coal-fired plant is lower than the heat rate of the nuclear plant because it uses higher steam pressures and temperatures and provides

for reheating the steam. Fuel costs ranged from a low of 11.86 cents a million Btu for the BWR plant to a high of 18.90 cents a million Btu for the coal-fired plant.

The fuel costs shown here have been levelized for the first twelve years of operation, the period over which the cost of the nuclear fuel was guaranteed to TVA. The levelized fuel cost is the uniform annual cost which has the same present value as the variable costs of the proposals.

The estimated capital cost per kilowatt of capacity for the nuclear plant TVA chose to build is about the same as the coal-fired plant--$116 compared with $117. One reason the costs were so close is the large size of the units. It has taken years of technological development and cost cutting to reduce the cost of large, coal-fired plants and it is significant that the cost of nuclear plants, which are practically in their infancy and for which substantial future improvements in design and economies in erection seem highly likely, already are no higher in cost than coal-fired plants.

Approximately two-thirds of the estimated total direct cost of the nuclear plant is for equipment being supplied by the manufacturer under a firm contract price that is not subject to escalation, whereas only about 14 percent of the estimated total direct cost of the coal-fired plant is based on firm bids. This lends assurance to the adequacy of the estimates and is very important in times such as these, when costs are rising so steadily.

The lower investment in transmission facilities required by the nuclear power plant reflects the point already mentioned, that the Browns Ferry site is located somewhat nearer the area on our system where additional power supply is needed in 1970 than is the Cumberland City site.

Fixed charges for interest and depreciation are much the same for all three plants. In all cases, interest at 4½ percent and an economic life of 35 years were used.

The cost of fuel to produce a kilowatt-hour of electric energy is the product of the plant heat rate and the price which must be paid for the fuel, including interest cost on fuel inventory. In TVA's evaluation, the advantage which the coal-fired plant enjoyed in its heat rate was more than offset by the relatively higher cost of the coal, with the result that the BWR nuclear plant is estimated to produce a kilowatt-hour of electric energy for 1.25 mills for fuel compared with 1.69 mills for the coal-fired plant. These costs include an allowance for interest on the fuel inventory, which, for the nuclear power plant, makes up about 10 percent of the total fuel cost and which, for the coal-fired plant, makes up about 1 percent.

Not only are fuel costs lower for the nuclear plant, they have the added advantage to TVA of being more certain than the coal costs of the coal-fired plant. The coal bids provided for escalation of price beginning with the date of the bid and are based partly on the U. S. Bureau of Labor Statistics Wholesale Price Index and

partly on a labor and material index; escalation on the nuclear fuel for the BWR plant will not start until 1975, about nine years from now; and even then it is based wholly on the Wholesale Price Index which in the past has increased much less than indexes directly related to labor and material costs.

Operating and maintenance costs of the nuclear plant include special costs that do not arise with a coal-fired plant, including the disposal of all radioactive materials. But these special costs are more than offset by the much higher operation and maintenance costs of the coal-handling facilities in a coal-fired plant. A staff of about 150 people is estimated for the nuclear power plant compared with about 250 for the coal-fired plant; most of the difference is for the operation and maintenance of coal-handling equipment.

In summary, the total cost of energy from the boiling water reactor plant delivered to the transmission system is estimated to be 2.39 mills a kilowatt-hour compared with 2.90 mills for energy from the lowest cost coal-fired plant that would meet system needs. The savings are estimated to be equivalent to $8 million a year during the first 12 years of operation, with the possibility of higher annual savings after this initial operating period.

Conclusion

In closing, it should be emphasized that TVA has no special preference between coal-fired and nuclear plants for producing electric power. TVA's interest is to use the power supply facilities which result in

the lowest cost so it may continue to fulfill its responsibility to serve electric consumers at the lowest possible rates.

True, TVA has a particular responsibility for multipurpose water control projects which provide many benefits, including flood control, navigation, municipal and industrial water supply, recreation, and hydroelectric power. A combination of thermal and hydro power is highly advantageous for a regional power supply. TVA has owned coal-fired generating capacity since the day it started operations. When opportunities for further economical hydro power development became minimal, it added to its coal-fired capacity to meet load growth.

Today, nuclear power offers an alternative to coal-fired thermal plants and portends to be an even stronger competitor for meeting future power needs. We expect that coal will leave no economic stone unturned in meeting that challenge. TVA will continue as in the past to evaluate and to compare before deciding on future plants.

With those of you who produce coal and those who transport it, TVA has a mutual interest. It is to keep the delivered cost of coal competitive.

TVA expects to continue to cooperate with the coal industry, with railroads, and with barge and truck lines to work toward this mutual interest so TVA may best fulfill its responsibility to the electric consumer of this region.

* * *

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DEFENDANT'S EXHIBIT 136

Caution: Commonwealth Edison is hazardous to your health

Commonwealth Edison Company is the biggest coal user in the city, currently consuming over 3,900,000 tons of coal a year. This results in an annual discharge of over 234,000 tons of deadly sulphur dioxide into Chicago's air.

Edison has opposed the enforcement of the 1968 Chicago ordinance requiring reduction in the level of sulphur in fuels used in Chicago.

Commonwealth Edison's official position is callously indifferent to the public interest:

Edison's Public Statement
Edison intends to comply with the ordinance deadlines which existed prior to the extension.

Fact
Wrong. Even before the City Council extended the compliance deadline, Edison had sought an administrative exemption from the low-sulphur limitation. Under Edison's own proposals, Edison will be consuming 2.1 million tons of high-sulphur coal in 1969 with a resultant discharge of 147,000 tons of sulphur dioxide into Chicago's atmosphere.

Edison's Public Statement
Low-sulphur coal is not available in Illinois.

Fact
In 1968 Peabody Coal Company agreed to mine low-sulphur coal reserves near Troy, Illinois. Peabody has since abandoned its proposal. Yet Peabody continues to be a major supplier of Edison's coal needs. Why didn't Edison use its economic leverage against Peabody to demand low-sulphur coal from Peabody? New York's Consolidated Edison demanded and is now receiving coal with a less than 1% sulphur content from its suppliers. In addition, 3 out of 4 Edison generating stations in Chicago have natural gas capacity. Why doesn't Edison ask the gas utilities to supply gas power on a full-time basis?

Edison's Public Statement
Edison is doing everything it can to combat air pollution.

Fact
Wrong. Edison's generating plants pour thousands of tons of particulate matter into Chicago's atmosphere every year. Edison's present air pollution control devices (precipitators) are highly inefficient by current technological standards. If Edison persists in using high sulphur coal it could at least provide more efficient precipitators.

We, The Hyde Park-Kenwood Community Conference, on behalf of the citizens of Chicago want to know what Edison will do to meet next year's compliance deadline. Will next year bring a new extension demand or will Edison comply with the sulphur limitations?

We await Edison's reply.

The Hyde Park-Kenwood Community Conference

5200 South Harper, Chicago, Illinois 60637
KAI NEBEL, Chairman

DEFENDANT'S EXHIBIT 137

CHICAGO SUN-TIMES, Fri., Dec. 12, 1969

Before everyone runs out of breath talking about pollution,

we're doing something to clear the air.

Gas is the cleanest energy there is anywhere. It's cleaner to produce and cleaner to use than coal, oil or gasoline.

IN CHICAGO

Most Chicago residents use natural gas for heating, cooking, clothes drying and water heating. And it's a plain fact that the more Chicago uses gas for these purposes, the cleaner our air will be.

Commonwealth Edison Company is one of our customers. Our sales to Edison during the past year totaled about 241 million therms of gas, more than triple the quantity they bought from us four years ago. The gas we sold them replaced 1.19 million tons of coal for making electricity, and eliminated 83,100 tons of sulphur dioxide from the air.

During the last six years, our sales to Edison totaled more than 846 million therms. It replaced 4.1 million tons of coal and eliminated 290,500 tons of sulphur dioxide from the air we breathe.

Gas-fired incinerators and fume incinerators are now being used by commercial, industrial and residential customers to dispose of waste materials and eliminate obnoxious odors. More of this equipment is being installed every year.

LOOK AT THE RECORD

In Chicago alone since January 1, 1964, gas has replaced coal and oil-burning equipment for commercial, industrial and residential purposes at a steadily increasing rate. Those replacements are now eliminating about 200,000 tons of sulphur dioxide pollution from the air each year.

GAS SUPPLY

We have repeatedly pointed out, that because of physical and economic limitations, natural gas alone cannot solve the total problem. Nevertheless, Peoples Gas is doing everything in its power to decrease air pollution by increasing the use and supply of natural gas.

During the past six years, Peoples Gas has spent 512 million dollars to build additional pipelines and increase its underground storage capacity. On January 1, 1964 our system's daily delivery capacity was 2.8 billion cubic feet. Now it is 4.9 billion cubic feet—the equivalent of 233,000 tons of coal or 32 million gallons of oil per day.

PLANS FOR 1970

In the coming year, we plan to spend 51 million dollars more to expand our supply and storage system. That will increase the supply of natural gas by an additional 528 million cubic feet per day—for even more clean air.

Peoples Gas

DX 138

STEAM-ELECTRIC PLANT FACTORS

1969 EDITION

(Fuel Consumption and Costs, Plant Capacity, Net Generation, 1968, and Planned Capacity, 1969-1975.)

AN ANNUAL STUDY BY THE DIVISION OF ECONOMICS AND STATISTICS

Nineteenth Edition, November 1969

* * *

NATIONAL COAL ASSOCIATION
1130 Seventeenth St., N.W.
Washington, D.C. 20036

Price: $20.00
Foreign Mailings: $25.00

Line No.	City	Company	Plant	Installed Generating Capacity (Thous. Kw)*	Net Generation (Million Kwh)*	Fuel Designed For: C-Coal S-Stoker P-Pulv'd. O-Oil G-Gas	Coal: Tons (Thous.)	Coal: Cost per Ton F.O.B. Plant	Oil: Barrels (Thous.)	Oil: Cost per Barrel F.O.B. Plant	Oil: Cost per Barrel As Burned	Oil: BTU per Gallon	Gas: Million Cubic Feet	Gas: Cost as Burned (¢/MCF)	Gas: BTU per Cubic Foot	Cost per Million BTU (Cents): F.O.B. Plant* Coal	Cost per Million BTU (Cents): As Burned Coal	Cost per Million BTU (Cents): As Burned Oil	Cost per Million BTU (Cents): As Burned Gas	Percent of Consumption in B.T.U.: Coal	Percent of Consumption in B.T.U.: Oil	Percent of Consumption in B.T.U.: Gas	Line No.
				(1)	(2)	(3)	(4)	(5)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	
	WEST NORTH CENTRAL - Cont'd																						
	IOWA - Cont'd																						
38	Spencer	Corn Belt Power Cooperative	Wisdom	37.5	162.0	C(P)G	30	$6.39	-	$ -	$ -	-	1,427	28.1	1,000	33.3	33.3 5	-	28.1	29	-	71	38
39	Montpelier	Eastern Iowa Light & Power Coop.	Montpelier	35.0	237.0	C	107	6.30	3	na	4.32	138,000	-	-	-	24.7	25.4	74.5	-	99	1	-	39
40	Creston	Southwestern Federated Power Coop.	Creston #2 13	22.5	-	OG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40
		TOTAL IOWA		2,729.3	11,196.4		3,175	5.67	105	4.22	4.22	141,880	64,411	26.7	1,020	26.5	27.4	72.7	26.2	51	-	49	
	KANSAS																						
1	Colby	Central Kansas Power Company	Colby	12.0	63.3	OG	-	-	7	4.21	4.12	150,000	1,047	22.1	948	-	-	65.5	23.3	-	4	96	1
2	Hays	"	Hays	19.0	64.1	OG	-	-	7	4.37	4.32	150,000	1,047	24.0	959	-	-	68.6	25.0	-	4	96	2
3	Hills City	"	Ross Beach #1	12.7	71.1	OG	-	-	5	4.36	4.27	150,000	1,045	22.1	948	-	-	67.7	23.3	-	3	97	3
4	Hills City	"	Ross Beach #2	22.0	175.0	OG	-	-	13	4.36	4.27	150,000	2,254	22.1	948	-	-	67.7	23.3	-	4	96	4
5	Liberal	Central Telephone & Utls. Corp. 38	Cimarron River	73.6	360.4	G	-	-	-	-	-	-	4,301	36.5	1,027	-	-	-	35.5	-	-	100	5
6	Concordia	"	Concordia	8.0	2.5	OG	-	-	-	-	-	-	50	na	1,000 7	-	-	-	na	-	-	100	6
7	Dodge City	"	Fort Dodge	30.8	146.7	G	-	-	4	4.30	4.34	150,000	1,983	21.0	1,003	-	-	68.9	20.9	-	1	99	7
8	Great Bend	"	A. Mullergren	133.5	585.3	G	-	-	15	4.00	4.01	150,000	6,763	24.4	967	-	-	63.7	25.2	-	1	99	8
9	Riverton	Empire District Electric Co.	Riverton	155.0	744.3	C(P)OG	36	5.80	30	2.11	2.23	155,000	7,568	22.6	1,042	22.7	24.3	34.2	21.7	10	2	88	9
10	Wichita	Kansas Gas & Electric Company	Gordon Evans	539.3	2,603.3	OG	-	-	11	na	1.39	147,249	26,358	21.2	982	-	-	22.4	21.6	-	-	100	10
11	Wichita	"	Murray Gill	348.3	1,787.1	OG	-	-	16	na	1.38	149,714	18,445	21.9	1,013	-	-	22.0	21.6	-	1	99	11
12	Parsons	"	Neosho	113.5	191.8	C(S)OG	0.1	na	23	na	2.37	150,857	2,195	25.2	1,039	na	24.4	37.3	24.3	-	6	94	12
13	Wichita	"	Ripley	87.3	142.1	OG	-	-	15	na	1.34	143,786	1,836	22.5	1,031	-	-	22.1	21.8	-	5	95	13
14	Wichita	"	Wichita	20.0	(0.6)	OG	-	-	-	-	-	-	24	na	1,000 7	-	-	-	21.0	-	-	100	14
15	Abilene	Kansas Power & Light Company	Abilene	33.8	34.7	OG	-	-	9	2.47	2.45	150,000	452	24.1	987	-	-	38.9	24.4	-	11	89	15
16	Hutchinson	"	Hutchinson	252.2	1,265.9	OG	-	-	49	2.23	2.64	154,000	13,273	26.1	1,027	-	-	41.6 5	23.5	-	2	98	16
17	Lawrence	"	Lawrence	210.2	957.8	COG	59	5.89	8	2.82	2.49	144,299	8,729	23.2	1,029	24.2	25.5	41.6 5	22.6	14	-	86	17
18	Tecumseh	"	Tecumseh	346.1	1,501.6	COG	80	5.85	7	2.77	2.67	147,501	13,931	23.3	1,035	23.8	25.2 5	43.9 5	22.5	12	-	88	18
19	Anthony	Anthony, City of	Anthony 7	5.8	14.2	G	-	-	-	-	-	-	235	na	1,050 6	-	-	-	na	-	-	100	19
20	Chanute	Chanute, City of	Chanute 7	19.0	47.4	OG	-	-	9	na	na	150,000 6	690	na	1,000 7	-	-	40.6	24.2	-	8	92	20
21	Clay Center	Clay Center Mun. Light & Water	Clay Center 7	12.5	19.8	OG	-	-	1	na	na	150,000 6	340	na	960 7	-	-	na	na	-	2	98	21
22	Coffeyville	Coffeyville Mun. Light & Power	Coffeyville	40.3	94.7	OG	-	-	2	na	2.80 7	144,000	1,335	24.2 7	1,000	-	-	46.3	24.2	-	1	99	22
23	Iola	Iola, City of	Iola 7	9.5	5.5	OG	-	-	-	-	-	-	102	na	937 7	-	-	-	27.8	-	-	100	23
24	Kansas City	Kansas City Bd. of Public Utils.	Kaw	161.3	561.6	C(P)G	93	6.21	-	-	-	-	5,492	23.8	1,005	28.5	28.5	-	24.1 5	27	-	73	24
25	Kansas City	"	Quindaro #2	104.5	232.6	C(P)G	19	5.91	-	-	-	-	3,006	24.1	951	23.9	23.9	-	25.8 5	14	-	86	25
26	Kansas City	"	Quindaro #3	81.6	337.4	C(P)G	174	5.94	-	-	-	-	424	23.2	950	24.1	24.1	-	24.8 5	91	-	9	26
27	Larned	Larned Water & Electric Dept.	Larned 7	12.8	16.4	G	-	-	1	na	na	150,000 6	330	na	1,050 6	-	-	na	na	-	2	98	27
28	McPherson	McPherson Water & Electric Dept.	McPherson #1	25.5	1.7	G	-	-	-	-	-	-	37	27.9	1,000	-	-	-	27.9	-	-	100	28
29	McPherson	"	McPherson #2	32.0	124.5	G	-	-	6	2.35	2.35	139,400	1,565	24.4	960	-	-	30.2 5	25.4	-	3	97	29
30	Ottawa	Ottawa Water & Light Department	Ottawa	6.5	0.2	OG	-	-	-	-	-	-	15	25.0	1,000	-	-	-	25.0	-	-	100	30
31	Pratt	Pratt Mun. Electric & Water Dept.	Pratt	27.8	34.9	G	-	-	2	na	na	150,000 6	553	na	867	-	-	na	na	-	3	97	31
32	Wellington	Wellington Light Department	Wellington 7	14.5	44.8	OG	-	-	-	-	-	-	664	na	1,050 6	-	-	-	na	-	-	100	32
33	Winfield	Winfield Mun. Light & Power Plant	Winfield 7	20.0	61.6	G	-	-	0.7	na	na	150,000 6	770	na	1,050 6	-	-	na	na	-	1	99	33
34	Garden City	Wheatland Electric Coop., Inc.	Garden City 7	28.5	167.1	OG	-	-	17	3.96 39	3.96 39	137,600 7	2,725	18.2 39	889 7	-	-	68.6 39	20.4 39	-	4	96	34
		TOTAL KANSAS		3,019.4	12,461.4		461	5.96	258	3.02	2.74	150,110	129,564	23.1	1,003	24.8	25.2	43.5	23.0	8	1	91	
	MINNESOTA																						
1	Albert Lea	Interstate Power Company	Albert Lea 7	18.5	22.1	OG	-	-	14	na	na	150,000 6	363	na	1,050 6	-	-	na	na	-	19	81	1
2	Sherburn	"	Fox Lake	104.6	521.9	C(P)OG	19	8.37	211	2.40	2.41	153,684	4,041	25.8	1,011	37.3	39.4	38.1	25.6	7	23	70	2
3	Aurora	Minnesota Power & Light Co.	Aurora	116.1	637.5	C(P)	287	9.10	-	-	-	-	-	-	-	35.0	36.0	-	-	100	-	-	3
4	Cohasset	"	Clay Boswell	150.0	1,023.2	C(P)	412	9.44	-	-	-	-	-	-	-	35.7	36.0	-	-	100	-	-	4
5	Duluth	"	M. L. Hibbard	122.5	445.2	C(P)G	138	8.89	-	-	-	-	2,585	29.3	1,014	34.2	36.0	-	28.9	58	-	42	5
6	Minneapolis	Northern States Power Co. (Minn.)	Black Dog	456.7	2,569.8	C(P)G	552	6.38	2	4.53	4.41	134,200	15,292	23.6	1,013	28.4	28.2	78.2	23.3	44	-	56	6
7	St. Paul	"	High Bridge	463.8	2,565.7	C(SP)G	406	6.36	37	4.45	5.12	134,200	18,563 40	23.7	1,013	28.2	28.3	90.8	23.4	32	1	67	7

XXX

Table 1. Steam-Electric Plant Capacity, Net[illegible]uel Consumption, and Unit Costs, 1968

Line No.	City	Company	Plant	Installed Generating Capacity (Thous. Kw)*	Net Generation (Million Kwh)*	Fuel Designed For: C-Coal, S-Stoker, P-Pulv'd., O-Oil, G-Gas	Coal: Tons (Thous.)	Coal: Cost per Ton F.O.B. Plant	Oil: Barrels (Thous.)	Oil: Cost per Barrel F.O.B. Plant	Oil: Cost per Barrel As Burned	Oil: BTU per Gallon	Gas: Million Cubic Feet	Gas: Cost as Burned (¢-MCF)	Gas: BTU per Cubic Foot	Cost per Million BTU (Cents): F.O.B. Plant* Coal	Cost per Million BTU (Cents): As Burned Coal	Cost per Million BTU (Cents): As Burned Oil	Cost per Million BTU (Cents): As Burned Gas	Percent of Consumption in B.T.U.: Coal	Percent of Consumption in B.T.U.: Oil	Percent of Consumption in B.T.U.: Gas	Line No.
				(1)	(2)	(3)	(4)	(5)	(6)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	
	WEST NORTH CENTRAL - Cont'd																						
	MISSOURI - Cont'd																						
16	St. Joseph	St. Joseph Light & Power Company	Lake Road	150.5	698.5	OCG	51	$7.07	4	$3.06	$3.14	151,345	9,350	21.7	974	31.9	35.6	49.6	22.3	11	-	89	16
17	St. Louis	Union Electric Company	Ashley	70.0	69.4	C(P)	81	6.10	0.7	4.07	4.01	152,000	-	-	-	26.9	27.8	62.8	-	100	-	-	17
18	St. Louis	"	Meramec	800.0	5,485.5	C(P)G	2,266	4.76	-	-	-	-	2,961 44	24.0	1,039	21.3	21.9	-	23.1	94	-	6	18
19	St. Louis	"	Mound	40.0	22.2	OG	-	-	19	2.99	3.00	152,000	318	24.1	1,039	-	-	47.8	23.2	-	27	73	19
20	West Alton	"	Sioux	976.0	3,500.3	C(P)O	1,464	4.52	16	3.87	3.86	137,000	-	-	-	19.9	20.0	67.3	-	100	-	-	20
21	Chillicothe	Chillicothe Municipal Utilities	Chillicothe 6j 7	15.0	48.8	C(S)	42	na	-	-	-	-	-	-	-	na	na	-	-	100	-	-	21
22	Columbia	Columbia Water & Light Dept.	Columbia 6e	79.2 33	190.0 33	C(S)	130	6.05	1	3.86	3.86	138,700	74	35.0	1,000	27.1	27.1	66.3	35.0	97	-	3	22
23	Fulton	Fulton Department of Utilities	Fulton 2 6b	11.5	28.0	C(S)	28	na	-	-	-	-	-	-	-	na	24.8	-	-	100	-	-	23
24	Hannibal	Hannibal Board of Public Works	Hannibal	34.0	72.0	C(SP)	37	7.74	-	-	-	-	126	39.5	1,000	32.3	32.2	-	39.5	88	-	12	24
25	Independence	Independence Power & Light Dept.	Blue Valley 6j	115.0	344.7	OCG	17	7.78	-	-	-	-	3,706	22.8	949	32.5	32.5	-	24.1	10	-	90	25
26	Independence	"	Dodgion Street 6j	15.5	-	OG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26
27	Macon	Macon Municpal Utilities	Macon 7	5.0	6.8	CG	8	na	-	-	-	-	-	-	-	na	na	-	-	100	-	-	27
28	Marshall	Marshall Municipal Utilities	Marshall 7	30.5	53.7	CG	4	na	-	-	-	-	690	na	1,000 7	na	na	-	na	11	-	89	28
29	Poplar Bluff	Poplar Bluff Bd. of Public Works	Poplar Bluff	16.5	21.8	C(S)OG	0.8	7.48	-	-	-	-	432	28.9	1,000	32.5	32.5	-	28.9	4	-	96	29
30	Springfield	Springfield Utilities	James River 6j	148.0	644.0	CG	20	7.66	-	-	-	-	6,604	22.4	1,011	31.2	31.5	-	22.2	7	-	93	30
31	Springfield	"	Main Street 6j	20.0	-	OG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31
32	Randolph Co.	Associated Electric Cooperative	Thomas Hill 7	175.0	1,180.0	C 3	523	4.26 39	-	-	-	-	-	-	-	20.0	39 20.5 39	-	-	100	-	-	32
33	Chamois	Central Electric Power Coop.	Chamois	59.0	385.6	C(P) 3	186	5.79	-	-	-	-	-	-	-	25.4	25.6	-	-	100	-	-	33
34	Missouri City	Northwest Elec. Power Coop., Inc.	Cameron	40.0	150.7	C(P)O	90	6.60	3	na	na	150,852	-	-	-	29.1	29.5	na	-	99	1	-	34
35	Palmyra	Northeast Missouri Elec. Pwr. Coop.	South River 7	15.0	27.8	C	21	na	-	-	-	-	-	-	-	na	na	-	-	100	-	-	35
		TOTAL MISSOURI		4,320.8	18,285.1		7,167	4.71	58	3.54	3.58	145,250	43,635	23.1	971	21.7	22.1	58.9	23.8	79	-	21	
	NEBRASKA																						
1	Alliance	Alliance, City of	Alliance	16.5	22.5	C(S)G	1	na	-	-	-	-	391	na	1,095 7	na	na	-	28.4	5	-	95	1
2	Fairbury	Fairbury Light & Water Dept.	Fairbury 2 6	21.0	30.0	OG	-	-	3	na	na	150,000	415	na	900 7	-	-	na	na	-	5	95	2
3	Fremont	Fremont Dept. of Utilities	Fremont No. 1 2	21.0	49.0	C(S)G	6	8.04 7	-	-	-	-	670	27.5 7	1,000 7	32.2	33.2 5	-	27.5	18	-	82	3
4	Fremont	"	Fremont No. 2	41.2	143.0	CG	9	8.04	-	-	-	-	1,641	27.5	1,000	32.2	33.2 5	-	27.5	12	-	88	4
5	Grand Island	Grand Island Mun. Light System	C. W. Burdick 6c	38.5	122.8	OG	-	-	3	3.28	3.29	151,000	1,643	27.0	955	-	-	51.9	28.3	-	1	99	5
6	Grand Island	"	Pine Street 6c	12.5	19.3	OG	-	-	0.8	3.29	3.29	151,000	365	27.0	955	-	-	51.9	28.3	-	1	99	6
7	Hastings	Hastings Utilities	Hastings	54.0	90.0	OG	-	-	5	3.36	3.36	153,000	1,316	27.3	950	-	-	52.3	28.7	-	3	97	7
8	Lincoln	Lincoln Commercial Light Dept.	A Street 6d 2	8.9	16.6	C(SP)OG	1	na	0.3	na	na	150,000 4	366	na	1,050 4	na	32.1	48.2	27.8	6	-	94	8
9	Schuyler	Schuyler Dept. of Utilities	Schuyler 7	9.0	9.0	OG	-	-	2	na	na	130,000 4	135	na	1,050 4	-	-	na	na	-	7	93	9
10	Lexington	Cent. Nebr. Pub. Pwr. & Irrig. Dist.	Canaday	108.8	458.5	OG	-	-	13	2.96	2.96	150,000	4,827	27.1	942	-	-	46.9	28.7	-	2	98	10
11	Scottsbluff	Consumers Pub. Power Dist. 45	Bluffs	42.2	174.3	OG	-	-	2 46	na	2.44	151,848	2,142	23.2	1,073	-	-	38.2	21.7	-	1	99	11
12	Ogallala	"	Ogallala 2	7.5	25.2	OG	-	-	0.5	na	na	150,000 4	420	na	961 7	-	-	na	na	-	1	99	12
13	Hallam	"	Sheldon	227.8	774.5	CG	83	na	-	-	-	-	6,092	26.0	1,010	na	31.6	-	25.6	25	-	75	13
14	Lincoln	Nebraska Public Power System	K Street	29.3	34.3	C(P)OG	3	7.89	4	3.26	3.26	149,848	811	27.7	1,005	30.5	30.4	51.8	27.6	13	3	84	14
15	Bellevue	"	Kramer	112.5	339.2	C(P)G	48	7.59	-	-	-	-	3,272	26.3	1,012	30.6	30.6	-	26.0	26	-	74	15
16	Omaha	Omaha Public Power District	Jones Street	160.0	47.5	C(SP)G	9	7.33	-	-	-	-	358	26.2	1,021	31.0	32.8 5	-	25.8	27	-	73	16
17	Omaha	"	North Omaha	600.0	2,787.0	C(P)G	371	7.29	-	-	-	-	19,101	26.2	1,021	30.0	30.9	-	25.7	32	-	68	17
18	Omaha	"	South Omaha	20.0	49.6	OG	-	-	6	3.33	3.45	151,836	237	26.7	1,021	-	-	54.2	26.2	-	13	87	18
		TOTAL NEBRASKA		1,330.7	5,212.3		533	7.35	40	3.17	3.15	150,914	44,441	26.3	1,006	30.2	31.1	49.6	26.2	23	-	77	
	NORTH DAKOTA																						
1	Beulah	Montana-Dakota Utilities Company	Beulah 2	13.5	40.7	C(S)	64 42	na	-	-	-	-	-	-	-	na	14.7	-	-	100	-	-	1
2	Mandan	"	Heskett	100.0	510.7	C(S)G	467 [illegible]	na	-	-	-	-	-	-	-	na	20.0	-	-	100	-	-	2
3	Williston	"	Williston 2	2.0	(0.1)	OG	-	-	-	-	-	-	13	na	1,050 4	-	-	-	30.4	-	-	100	3
4	Minot	Northern States Power Co. (Minn.)	Bison 2	10.0	10.7	C(S)	[illegible]	na	-	-	-	-	-	-	-	na	25.4	-	-	100	-	-	4
5	Fargo	"	Fargo 2	20.0	28.6	C(S)	[illegible]	na	-	-	-	-	-	-	-	na	31.3	-	-	100	-	-	5
6	Grand Forks	"	Grand Forks 2	16.0	30.9	C(S)	59	na	-	-	-	-	-	-	-	na	31.1	-	-	100	-	-	6
7	Devils Lake	Otter Tail Power Company	Devils Lake 2	12.5	29.1	C(S)	55 42	na	-	-	-	-	-	-	-	na	36.0	-	-	100	-	-	7

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Table 6. The Other Plants or Units Planned or Under Construction, 1969-75: Hydro-Electric, Internal Combustion and Gas Turbine

CITY	COMPANY	PLANT	N-NEW E-EXISTING PLANT	TYPE OF PLANT 1	1969 NAMEPLATE 2	1969 DEPENDABLE 3	1970 NAMEPLATE 2	1970 DEPENDABLE 3	1971 NAMEPLATE 2	1971 DEPENDABLE 3	1972 NAMEPLATE 2	1972 DEPENDABLE 3	1973 CAPACITY 4	1974 CAPACITY 4	1975 CAPACITY 4
NEW ENGLAND															
CONNECTICUT															
1. Branford	Connecticut Light & Power Company	Branford #1	N	GT	20,400	20,400	-	-	-	-	-	-	-	-	-
2. Unassigned	"	Cos Cob #1 - 3	N	GT	68,700 7	68,000	-	-	-	-	-	-	-	-	-
3. Enfield	"	Enfield #1	N	GT	20,400	20,400	-	-	-	-	-	-	-	-	-
4. Erving	"	Northfield #1 - 4	N	H	-	-	-	-	750,000 6 8	750,000	250,000 4	250,000	-	-	-
5. na	"	Tunnel #3	N	GT	20,400	20,400	-	-	-	-	-	-	-	-	-
TOTAL CONNECTICUT				GT	129,900	129,200	-	-	-	-	-	-	-	-	-
				H	-	-	-	-	750,000	750,000	250,000	250,000	-	-	-
MASSACHUSETTS															
1. Boston	Boston Edison Company	Edgar #J1, J2	E	GT	7,500	8,250	-	-	-	-	-	-	-	-	-
2. Framingham	"	Framingham #1 - 3	N	GT	50,250 9	51,000	-	-	-	-	-	-	-	-	-
3. Everett	"	Mystic	E	GT	100,500 10	100,000	-	-	-	-	-	-	-	-	-
4. na	"	W. Medway #1 - 3	N	GT	-	-	[illegible] 4	220,000	-	-	-	-	-	-	-
5. Marthas Vineyard	Cape & Vineyard Electric Company	Vineyard #1 & 2	N	IC	5,500	6,000	-	-	-	-	-	-	-	-	-
6. Somerset	Eastern Utility Associates	Somerset	N	GT	-	-	[illegible]	22,000	-	-	-	-	-	-	-
7. Provincetown	New Bedford Gas & Edison Light Co.	Provincetown	N	IC	2,750	3,000	-	-	-	-	-	-	-	-	-
8. na	New England Power Company	Bear Swamp	N	H	-	-	-	-	-	-	-	-	-	600,000	-
9. Salem Harbor	"	Salem Harbor	E	GT	-	-	[illegible]	16,000	-	-	-	-	-	-	-
10. Uxbridge	"	Uxbridge #1 & 2	N	GT	-	-	[illegible]	46,000	-	-	-	-	-	-	-
11. na	Western Massachusetts Electric Co.	Doreen #1	N	GT	20,400	20,400	-	-	-	-	-	-	-	-	-
12. Pittsfield	"	Silver Lake	N	GT	80,200	80,200	-	-	-	-	-	-	-	-	-
13. na	"	Woodland Road #1	N	GT	20,400	20,400	-	-	-	-	-	-	-	-	-
TOTAL MASSACHUSETTS				GT	278,750	280,250	[illegible]	304,000	-	-	-	-	-	-	-
				H	-	-	-	-	-	-	-	-	-	600,000	-
				IC	8,250	9,000	-	-	-	-	-	-	-	-	-
NEW HAMPSHIRE															
1. na	Public Service Co. of New Hampshire	Lost Nation #1	N	GT	19,000	19,000	-	-	-	-	-	-	-	-	-
2. Manchester	"	Merrimack #4	E	GT	25,000	25,000	-	-	-	-	-	-	-	-	-
TOTAL NEW HAMPSHIRE				GT	44,000	44,000	-	-	-	-	-	-	-	-	-
MIDDLE ATLANTIC															
NEW JERSEY															
1. Atlantic City	Atlantic City Electric Company	Missouri Ave. #1 - 3	E	GT	55,800 5 11	64,800	-	-	-	-	-	-	-	-	-
2. Morris County	Jersey Central Power & Light Co.	Longwood #1, 2 & 3	N	H	-	-	-	-	121,500 6 12	130,000	-	-	-	-	-
3. Holland Township	Metropolitan Edison Company	Gilbert Riegal	N	GT	-	-	125,000 4	125,000	-	-	-	-	-	-	-
4. Kearny	Public Service Electric & Gas Co.	Kearny #10 & 11	E	GT	230,400 13	280,000	-	-	-	-	-	-	-	-	-
5. Linden	"	Linden	E	GT	-	-	-	-	80,000	80,000	-	-	-	-	-
6. Rio Grande	"	Middle	N	GT	-	-	[illegible]	48,000	-	-	-	-	-	-	-
7. Lower Alloway	"	Salem	N	GT	-	-	-	-	40,000	40,000	-	-	-	-	-
8. na	"	Unassigned	N	GT	-	-	115,000	140,000	420,000 4	420,000	-	-	-	-	-
TOTAL NEW JERSEY				GT	286,200	344,800	[illegible]	313,000	540,000	540,000	-	-	-	-	-
				H	-	-	-	-	121,500	130,000	-	-	-	-	-
NEW YORK															
1. South Cairo	Central Hudson Gas & Electric Co.	Copsackie	N	GT	21,600	24,000	-	-	-	-	-	-	-	-	-
2. na	"	Saugerties #1	N	GT	-	-	[illegible]	24,000	-	-	-	-	-	-	-
3. na	"	Sturgeon Pool	N	H	-	-	-	-	-	-	-	-	-	-	14,400
4. New York	Consolidated Edison Co. of N.Y.	Arthur Kill	E	GT	-	-	17,000	21,000	-	-	-	-	-	-	-
5. New York	"	Astoria #2 - 4	E	GT	-	-	[illegible]	555,000	-	-	-	-	-	-	-
6. New York	"	Cornwall	N	H	-	-	-	-	-	-	-	-	1,800,000 6	-	-
7. New York	"	59th Street	E	GT	17,102	21,000	-	-	-	-	-	-	-	-	-
8. New York	"	Hudson Avenue	E	GT	-	-	50,000	50,000	-	-	-	-	-	-	-
9. New York	"	Indian Point	E	GT	16,575	25,000	-	-	-	-	-	-	-	-	-
10. New York	"	Kent Avenue	E	GT	14,000	15,000	-	-	-	-	-	-	-	-	-
11. Freeport	Freeport, City of	Freeport #1 & 2	N	GT	20,000	20,328	-	-	-	-	-	-	10,000	-	-
12. Island Park	Long Island Lighting Company	Barrett #1 - 8	E	GT	-	-	[illegible] 14	168,800	-	-	-	-	-	-	-
13. na	"	East Hampton	N	GT	-	-	21,250	24,400	-	-	-	-	-	-	-
14. na	"	Inwood	N	GT	-	-	-	-	63,500	61,100	-	-	-	-	-
15. Mineola	"	Shoreham	N	GT	-	-	-	-	50,000	56,000	-	-	-	-	-
16. Albany	Niagara Mohawk Power Corporation	Albany	E	GT	165,000	180,000	-	-	-	-	-	-	-	-	-
17. Albany	"	Rotterdam	N	GT	-	-	60,000	184,000	-	-	-	-	-	-	-

Table 6. The Other Plants or Units Planned or Under Construction 1969-75: Hydro-Electric, Internal Combustion and Gas Turbine

CITY	COMPANY	PLANT	N-NEW E-EXISTING PLANT	TYPE OF PLANT 1	1969 NAMEPLATE 2	1969 DEPENDABLE 3	1970 NAMEPLATE 2	1970 DEPENDABLE 3	1971 NAMEPLATE 2	1971 DEPENDABLE 3	1972 NAMEPLATE 2	1972 DEPENDABLE 3	1973 CAPACITY 4	1974 CAPACITY 4	1975 CAPACITY 4
MIDDLE ATLANTIC - Cont'd															
NEW YORK - Cont'd															
18. Blenhein	New York State Power Authority	Blenheim-Gilboa	N	H	-	-					500,000	500,000	500,000	-	-
19. Rochester	Rochester Gas & Electric Corporation	R. E. Ginna	N	IC	4,500	4,500	-	-	-	-	-	-	-	-	-
20. Rochester	"	Station #3 - 9	E	GT	36,000 15	37,500	-	-	-	-	-	-	-	-	-
TOTAL NEW YORK				GT	290,277	322,828	[illegible]850	1,027,200	113,500	117,100	-	-	10,000	-	-
				H	-	-	-	-	-	-	500,000	500,000	2,300,000	-	14,400
				IC	4,500	4,500	-	-	-	-	-	-	-	-	-
PENNSYLVANIA															
1. East of Warren	Pennsylvania Electric Company	Seneca #1 - 3	N	H	380,000 6 16	380,000	-	-	-	-	-	-	-	-	-
2. Homer City	"	Homer City	N	IC	7,500	7,500	-	-	-	-	-	-	-	-	-
3. Newcastle	Pennsylvania Power Company	Newcastle	E	IC	6,000 5	6,000	-	-	-	-	-	-	-	-	-
4. Pottsville	Pennsylvania Power & Light Company	Fishbach #1 & 2	N	GT	37,200 17	40,000	-	-	-	-	-	-	-	-	-
5. na	"	Jenkins Laflin	N	GT	32,000	35,000	-	-	-	-	-	-	-	-	-
6. Lock Haven	"	Lock Haven #1	N	GT	18,600	20,000	-	-	-	-	-	-	-	-	-
7. na	"	Suburban	E	GT	29,250	34,000	-	-	-	-	-	-	-	-	-
8. Harrisburg	"	West Shore #1 - 2	N	GT	37,200 18	40,000	-	-	-	-	-	-	-	-	-
9. Chester	Philadelphia Electric Company	Chester	E	GT	55,800 19	64,000	-	-	18,600	21,300	-	-	-	-	-
10. Philadelphia	"	Delaware	E	GT	55,800 20	66,000	2[illegible]08	24,000	-	-	-	-	-	-	-
11. Philadelphia	"	Eddystone	E	GT	-	-	[illegible]400	24,000	-	-	-	-	-	-	-
12. Philadelphia	"	Falls	N	GT	-	-	61,200	72,000	20,400	24,000	-	-	-	-	-
13. Philadelphia	"	Moser	N	GT	-	-	61,200	72,000	-	-	-	-	-	-	-
14. Philadelphia	"	Schuylkill	E	GT	18,600	22,000	-	-	20,400	24,000	-	-	-	-	-
15. Philadelphia	"	West Chester	N	GT	-	-	-	-	98,800	115,600	-	-	-	-	-
16. Indiana County	Public Service Electric & Gas Co.	Conemaugh	N	IC	11,000	11,000	-	-	-	-	-	-	-	-	-
17. na	"	National Park	N	GT	18,600	20,000	-	-	-	-	-	-	-	-	-
TOTAL PENNSYLVANIA				GT	303,050	341,000	[illegible]208	192,000	158,200	184,900	-	-	-	-	-
				H	380,000	380,000	-	-	-	-	-	-	-	-	-
				IC	24,500	24,500	-	-	-	-	-	-	-	-	-
EAST NORTH CENTRAL															
ILLINOIS															
1. Chicago	Commonwealth Edison Company	Calumet	E	GT	220,000 21	220,000	7[illegible]300 22	76,000	-	-	-	-	-	-	-
2. Chicago	"	Electric Junction	N	GT	-	-	76,000	76,000	-	-	-	-	-	-	-
3. Joliet	"	Joliet	E	GT	147,000 23	147,000	-	-	-	-	-	-	-	-	-
4. Chicago	"	Lowbard	N	GT	132,900 24	132,900	-	-	-	-	-	-	-	-	-
5. Rockford	"	Sabrooke	E	GT	73,000 25	73,000	7[illegible]300 26	76,000	-	-	-	-	-	-	-
6. Oglesby	Illinois Power Company	Oglesby	N	GT	-	-	7[illegible]210	70,210	-	-	-	-	-	-	-
7. Stallings	"	Stallings	N	GT	-	-	108,000	100,000	-	-	-	-	-	-	-
8. Moline	Iowa-Illinois Gas & Electric Co.	Moline #1 - 4	E	GT	-	-	72,600 27	72,600	-	-	-	-	-	-	-
9. Marion	Southern Illinois Power Co-op.	Marion	E	GT	-	-	-	-	-	-	-	-	-	-	40,000
TOTAL ILLINOIS				GT	572,900	572,900	[illegible]810	470,810	-	-	-	-	-	-	40,000
INDIANA															
1. na	Public Service Company of Indiana	Miami Wabash # 6 & 7	E	GT	32,500 28	37,000	-	-	-	-	-	-	-	-	-
2. Fort Wayne	Fort Wayne, City of	na	E	GT	-	-	1[illegible]000	15,000	-	-	-	-	-	-	-
TOTAL INDIANA				GT	32,500	37,000	15,000	15,000	-	-	-	-	-	-	-
MICHIGAN															
1. Ludington	Consumers Power Company	Ludington	N	H	-	-	-	-	-	-	-	-	955,000	-	-
2. Comstock	"	Morrow B. E.	E	GT	17,500	20,000	-	-	-	-	-	-	-	-	-
3. Mackinaw City	"	Straits #1	N	GT	25,000	30,000	-	-	-	-	-	-	-	-	-
4. na	"	Thetford #1 - 4	N	GT	74,500 29	88,000	7[illegible]500 30	88,000	-	-	-	-	-	-	-
5. Port Huron	Detroit Edison Company	Colfax	N	IC	13,750	14,000	-	-	-	-	-	-	-	-	-
6. Cottrellville Twp.	"	Hancock #5 & 6	E	GT	-	-	7[illegible],300 31	95,000	-	-	-	-	-	-	-
7. Monroe	"	Monroe	E	IC	13,750	14,000	-	-	-	-	-	-	-	-	-
8. Monroe	"	Oliver	N	IC	13,750	14,000	-	-	-	-	-	-	-	-	-
9. Springfield	"	Placid	N	IC	13,750	14,000	-	-	-	-	-	-	-	-	-
10. [illegible] Twp.	"	Wilmont	N	IC	13,750	14,000	-	-	-	-	-	-	-	-	-
11. Marquette	Upper Peninsula Power Company	Red Jacket	N	IC	10,000	10,000	-	-	-	-	-	-	-	-	-
12. Wyandotte	Wyandotte, Dept. of Mun. Serv.	Wyandotte #6	E	GT	16,320 4	16,320	-	-	-	-	-	-	-	-	-
TOTAL MICHIGAN				GT	133,320	154,300	[illegible]300	183,000	-	-	-	-	-	-	-
				H	-	-	-	-	-	-	-	-	955,000	-	-
				IC	78,750	80,000	-	-	-	-	-	-	-	-	-

Table 6. The Other Plants or Units Planned or Under Construction ..-75: Hydro-Electric, Internal Combustion and Gas Turbine

City	Company	Plant	N-New E-Existing Plant	Type of Plant [1]	1969 Nameplate [2]	1969 Dependable [3]	1970 Nameplate [2]	1970 Dependable [3]	1971 Nameplate [2]	1971 Dependable [3]	1972 Nameplate [2]	1972 Dependable [3]	1973 Capacity [4]	1974 Capacity [4]	1975 Capacity [4]
EAST NORTH CENTRAL - Cont'd															
OHIO															
1. Cincinnati	Cincinnati Gas & Electric Company	Dicks Crk. #2 - 5	E	GT	72,640 [32]	95,000	-	-	-	-	-	-	-	-	-
2. Aberdeen	"	S.M. Stuart	N	IC	-	-	11,000 [6]	11,000	-	-	-	-	-	-	-
3. Columbus	Columbus & Southern Ohio Electric Co.	Walnut #8	E	GT	32,600 [5]	36,000	-	-	-	-	-	-	-	-	-
4. Dayton	Dayton Power & Light Company	Yankee Street	N	GT	55,782	69,000	-	-	-	-	-	-	-	-	-
TOTAL OHIO				GT	161,022	200,000	-	-	-	-	-	-	-	-	-
				IC	-	-	11,000	11,000	-	-	-	-	-	-	-
WISCONSIN															
1. Kaukauna	Kaukauna, City of	Kaukauna	N	GT	17,400	18,000	-	-	-	-	-	-	-	-	-
2. Superior	Lake Superior District Power Company	Flambeau #1	N	GT	20,000 [5]	20,000	-	-	-	-	-	-	-	-	-
3. Two Creeks	Wisconsin Electric Power Company	Point Beach	N	GT	20,000	20,000	-	-	-	-	-	-	-	-	-
4. Port Washington	"	Port Washington	E	GT	20,000	20,000	-	-	-	-	-	-	-	-	-
5. Green Bay	Wisconsin Public Service Corp.	Weston #31	E	GT	17,900 [5]	25,000	-	-	-	-	-	-	-	-	-
TOTAL WISCONSIN				GT	95,300	103,000	-	-	-	-	-	-	-	-	-
WEST NORTH CENTRAL															
IOWA															
1. Coralville	Iowa-Illinois Gas & Electric Co.	Coralville #1 - 4	E	GT	-	-	72 00 [33]	72,300	-	-	-	-	-	-	-
2. Charles City	Iowa Public Service Company	Charles City	E	GT	33,000	33,900	-	-	-	-	-	-	-	-	-
TOTAL IOWA				GT	33,000	33,900	72 00	72,300	-	-	-	-	-	-	-
KANSAS															
1. Colby	Central Kansas Power Company	Colby #3	E	GT	-	-	18 000	18,000	-	-	-	-	-	-	-
2. Kansas City	Kansas City Board of Public Utilities	Quindaro #3	E	GT	16,800	16,810	-	-	-	-	-	-	-	-	-
3. Wichita	Kansas Gas & Electric Company	Wichita	E	IC	2,500	2,700	-	-	-	-	-	-	-	-	-
TOTAL KANSAS				GT	16,800	16,810	18,000	18,000	-	-	-	-	-	-	-
				IC	2,500	2,700	-	-	-	-	-	-	-	-	-
MINNESOTA															
1. Marshall	Marshall, City of	Marshall	E	GT	19,700 [6]	19,700	-	-	-	-	-	-	-	-	-
2. St. Cloud	Northern States Power Company	Granite City #1 - 4	N	GT	69,300	78,600	-	-	-	-	-	-	-	-	-
3. Mankato	"	Key City #1 - 4	N	GT	-	-	69 00 [34]	78,600	-	-	-	-	-	-	-
TOTAL MINNESOTA				GT	89,000	98,300	69,.00	78,600	-	-	-	-	-	-	-
MISSOURI															
1. Carthage	Carthage, City of	Carthage #1 & 2	N	IC	-	-	4 00	4,400	4,400	4,400	-	-	-	-	-
2. Independence	Independence, City of	Substation #1 & 2	N	GT	30,000 [35]	30,000	-	-	-	-	-	-	-	-	-
3. Stockton	Southwestern Power Administration	Stockton #1	N	H	-	-	45,.00	45,200	-	-	-	-	-	-	-
TOTAL MISSOURI				GT	30,000	30,000	-	-	-	-	-	-	-	-	-
				H	-	-	45 00	45,200	-	-	-	-	-	-	-
				IC	-	-	4 00	4,400	4,400	4,400	-	-	-	-	-
SOUTH ATLANTIC															
FLORIDA															
1. St. Petersburg	Florida Power Corporation	Higgins	E	GT	67,000 [5]	67,000	-	-	-	-	-	-	-	-	-
2. Port St. Joe	"	Port St. Joe	N	GT	-	-	1[illegible] 00	18,000	-	-	-	-	-	-	-
3. Turner	"	Turner	E	GT	-	-	34,000	36,000	-	-	-	-	-	-	-
4. Lauderdale	Florida Power & Light Company	Lauderdale	E	GT	-	-	440.000 [36]	440,000	-	-	-	-	-	-	-
5. Gainesville	Gainesville, City of	Gainsville	E	GT	15,000 [5]	15,000	-	-	-	-	-	-	-	-	-
6. Jacksonville	Jacksonville, City of	Kennedy	E	GT	34,000 [5]	32,800	-	-	-	-	-	-	-	-	-
7. Jacksonville	"	Southside	E	GT	34,000 [5]	32,800	-	-	-	-	-	-	-	-	-
8. Lakeland	Lakeland, City of	Lakeland #3	E	IC	5,000	5,000	-	-	-	-	-	-	-	-	-
9. Tallahassee	Tallahassee, City of	West Side #1	N	GT	16,000 [4]	16,000	-	-	-	-	-	-	-	-	-
10. Tampa	Tampa Electric Company	Big Bend	N	GT	17,500 [5]	17,500	-	-	-	-	-	-	-	-	-
11. Tampa	"	Gannon F.J.	E	GT	17,500 [5]	17,500	-	-	-	-	-	-	-	-	-
TOTAL FLORIDA				GT	201,000	198,600	491,000	494,000	-	-	-	-	-	-	-
				IC	5,000	5,000	-	-	-	-	-	-	-	-	-

Table 6. The Other Plants or Units Planned or Under Construction, [illegible]-75: Hydro-Electric, Internal Combustion and Gas Turbine

CITY	COMPANY	PLANT	N-NEW E-EXISTING PLANT	TYPE OF PLANT 1	1969 NAMEPLATE 2	1969 DEPENDABLE 3	1970 NAMEPLATE 2	1970 DEPENDABLE 3	1971 NAMEPLATE 2	1971 DEPENDABLE 3	1972 NAMEPLATE 2	1972 DEPENDABLE 3	1973 CAPACITY 4	1974 CAPACITY 4	1975 CAPACITY 4
SOUTH ATLANTIC - Cont'd															
GEORGIA															
1. Bibb County	Georgia Power Company	Arkwright 5A & 5B	E	GT	34,000 37	34,000	-	-	-	-	-	-	-	-	-
2. Smyrna	"	Atkinson #1 & 2	E	GT	-	-	80,000 38	80,000	-	-	-	-	-	-	-
3. Savannah	Savannah Electric & Power Company	Port Wentworth	E	GT	19,200	19,200	-	-	-	-	-	-	-	-	-
4. na	Southeastern Power Administration	Carters #1 & 2	N	H	-	-	-	-	-	-	-	-	500,000 39	-	-
5. West Point	"	West Point #1 & 2	N	H	-	-	-	-	-	-	-	-	73,375 40	-	-
TOTAL GEORGIA				GT	53,200	53,200	80,000	80,000	-	-	-	-	-	-	-
				H	-	-	-	-	-	-	-	-	573,375	-	-
MARYLAND															
1. Baltimore	Baltimore Gas & Electric Company	North Cliff	N	GT	133,500 41	133,000	-	-	-	-	-	-	-	-	-
2. Baltimore	"	Richmond	N	GT	-	-	-	-	172,100	206,800	-	-	-	-	-
3. Baltimore	"	Riverside #6	E	GT	-	-	[illegible]2[illegible] 500	132,000	-	-	-	-	-	-	-
4. na	"	Unassigned	N	GT	-	-	1[illegible] 000	117,000	216,000	216,000	-	-	-	-	-
5. Baltimore	"	Westport #5	E	GT	121,500 5	132,000	-	-	-	-	-	-	-	-	-
6. Newbury	Potomac Electric Power Company	Morgantown	N	GT	-	-	-	-	34,600	40,000	-	-	-	-	-
TOTAL MARYLAND				GT	255,000	265,000	3[illegible] 500	249,000	422,700	462,800	-	-	-	-	-
NORTH CAROLINA															
1. Cape Fear	Carolina Power & Light Company	Cape Fear	E	GT	84,704 42	73,600	-	-	-	-	-	-	-	-	-
2. Sutton	"	Sutton B & C	E	GT	65,280 43	65,900	-	-	-	-	-	-	-	-	-
3. Lumberton	"	Weatherspoon	E	GT	-	-	7[illegible] 492 44	84,000	-	-	-	-	-	-	-
4. Draper	Duke Power Company	Dan River 6C	E	GT	29,000	29,000	-	-	-	-	-	-	-	-	-
5. Mount Holly	"	Riverbend 8C-11C	E	GT	144,000 45	144,000	-	-	-	-	-	-	-	-	-
6. na	"	Urquhart #1 & 2	N	GT	46,000 46	46,000	-	-	-	-	-	-	-	-	-
TOTAL NORTH CAROLINA				GT	368,984	358,500	7[illegible] 492	84,000	-	-	-	-	-	-	-
SOUTH CAROLINA															
1. Hartsville	Carolina Power & Light Company	H.B. Robinson	E	IC	5,000 47	5,000	-	-	-	-	-	-	-	-	-
2. Near Clemson	Duke Power Company	Keowee #1 & 2	N	H	-	-	4[illegible] 000 48	156,500	-	-	-	-	-	-	-
3. Charleston	South Carolina Electric & Gas Co.	Coit #1 & 2	N	GT	40,000 49	43,000	-	-	-	-	-	-	-	-	-
4. Lexington City	"	Saluda	N	H	-	-	[illegible] 000	70,000	-	-	-	-	-	-	-
5. Beech Island	"	Urquhart	E	GT	40,000	40,000	-	-	-	-	-	-	-	-	-
TOTAL SOUTH CAROLINA				GT	80,000	83,000	-	-	-	-	-	-	-	-	-
				H	-	-	[illegible] 000	226,500	-	-	-	-	-	-	-
				IC	5,000	5,000	-	-	-	-	-	-	-	-	-
VIRGINIA															
1. Chesterfield	Virginia Electric & Power Company	Chesterfield	E	GT	41,066 5	47,910	-	-	-	-	-	-	-	-	-
2. Portsmouth	"	Portsmouth	E	GT	143,731	168,000	-	-	-	-	-	-	-	-	-
TOTAL VIRGINIA				GT	184,797	215,910	-	-	-	-	-	-	-	-	-
EAST SOUTH CENTRAL															
ALABAMA															
1. Demopolis	Alabama Power Company	Demopolis #1 & 2	N	GT	50,000 50	50,000	-	-	-	-	-	-	-	-	-
2. Alabama River	Southeastern Power Administration	Millers Ferry	N	H	75,000 51	75,000	50,000 52	50,000	25,000	25,000	-	-	-	-	-
3. Gaston	Southern Electric Generating Co.	Gaston	E	GT	-	-	2[illegible] 000	20,000	-	-	-	-	-	-	-
4. na	U.S. Army Corps of Engineers	Jones Bluff #1,2,3,4	N	H	-	-	-	-	-	-	-	-	-	68,000 53	-
TOTAL ALABAMA				GT	50,000	50,000	20,000	20,000	-	-	-	-	-	-	-
				H	75,000	75,000	50,000	50,000	25,000	25,000	-	-	-	68,000	-
KENTUCKY															
1. na	Kentucky Utilities Company	Haefling	N	GT	-	-	5[illegible],000	51,000	-	-	-	-	-	-	-
2. Louisville	Louisville Gas & Electric Company	Zorn #1	E	GT	16,000	16,000	-	-	-	-	-	-	-	-	-
3. Owensboro	Owensboro, City of	Laurel	N	H	-	-	-	-	-	-	-	-	-	-	61,000
TOTAL KENTUCKY				GT	16,000	16,000	5[illegible] 000	51,000	-	-	-	-	-	-	-
				H	-	-	-	-	-	-	-	-	-	-	61,000

Table 6. The Other Plants or Units Planned or Under Construction, [illegible]9-75: Hydro-Electric, Internal Combustion and Gas Turbine

CITY	COMPANY	PLANT	N-NEW E-EXISTING PLANT	TYPE OF PLANT 1	1969 NAMEPLATE 2	1969 DEPENDABLE 3	1970 NAMEPLATE 2	1970 DEPENDABLE 3	1971 NAMEPLATE 2	1971 DEPENDABLE 3	1972 NAMEPLATE 2	1972 DEPENDABLE 3	1973 CAPACITY 4	1974 CAPACITY 4	1975 CAPACITY 4
EAST SOUTH CENTRAL - Cont'd															
MISSISSIPPI															
1. Watson	Mississippi Power Company	Watson	E	GT	-	-	0,000 4	40,000	-	-	-	-	-	-	-
2. Moselle	South Mississippi Electric Pwr. Assn.	Moselle	N	GT	14,000 4	14,000	-	-	28,000 4	28,000	-	-	-	-	-
3. Benndale	Southwest Mississippi Elec. Pwr. Assn.	Benndale	N	GT	-	-	-	-	17,000	17,000	-	-	-	-	-
TOTAL MISSISSIPPI				GT	14,000	14,000	0,000	40,000	45,000	45,000	-	-	-	-	-
TENNESSEE															
1. na	Tennessee Valley Authority	Cordell Hull 1, 2 & 3	N	H	-	-	-	-	66,666 56	66,666	33,333	33,333	-	-	-
2. na	"	Priest #1	N	H	28,000 4	28,000	-	-	-	-	-	-	-	-	-
3. Elk River	"	Tims Ford	N	H	-	-	-	-	45,000	40,000	-	-	-	-	-
TOTAL TENNESSEE				H	28,000	28,000	-	-	111,666	106,666	33,333	33,333	-	-	-
WEST SOUTH CENTRAL															
ARKANSAS															
1. na	Southwestern Power Administration	De Gray #1 & 2	N	H	-	-	-	-	68,000 6 53	68,000	-	-	-	-	-
2. na	"	Ozark #1 - 4	N	H	-	-	-	-	-	-	80,000 56	80,000	20,000	-	-
TOTAL ARKANSAS				H	-	-	-	-	68,000	68,000	80,000	80,000	20,000	-	-
LOUISIANA															
1. Thibodaux	Thibodaux, City of	Thibodaux	E	IC	6,250 4	6,250	-	-	-	-	-	-	-	-	-
TOTAL LOUISIANA				IC	6,250	6,250	-	-	-	-	-	-	-	-	-
OKLAHOMA															
1. Near Salina	Grand River Dam Authority	Salina #4, 5 & 6	N	H	-	-	-	-	129,600 6 57	129,600	-	-	-	-	-
2. na	Oklahoma Gas & Electric Company	Seminole #1	N	GT	-	-	-	-	22,000	19,000	-	-	-	-	-
3. na	Southwestern Power Administration	Broken Bow #1 & 2	N	H	-	-	0,000 58	86,000	-	-	-	-	-	-	-
4. na	"	Narrows	N	H	8,500	9,000	-	-	-	-	-	-	-	-	-
5. Locust Grove	"	Robert S. Kerr #1-4	N	H	-	-	55,000 59	55,000	55,000 60	55,000	-	-	-	-	-
6. na	"	Webbers Falls #1-3	N	H	-	-	-	-	-	-	40,000 61	40,000	20,000	-	-
TOTAL OKLAHOMA				GT	-	-	-	-	22,000	19,000	-	-	-	-	-
				H	8,500	9,000	155,000	141,000	184,600	184,600	40,000	40,000	20,000	-	-
TEXAS															
1. Lubbock	Lubbock, City of	Holly Avenue	E	GT	-	-	7,500	17,500	-	-	-	-	-	-	-
2. na	Sabina River Authority	Toledo Bend #1 & 2	N	H	80,000 62	85,000	-	-	-	-	-	-	-	-	-
TOTAL TEXAS				GT	-	-	'7,500	17,500	-	-	-	-	-	-	-
				H	80,000	85,000	-	-	-	-	-	-	-	-	-
MOUNTAIN															
ARIZONA															
1. na	Salt River (AIP) Dist. Proj.	Horse Mesa	N	H	-	-	-	-	-	-	93,500	93,500	-	-	-
2. na	"	Mormon Flats	N	H	-	-	3,000	3,000	48,600	48,600	-	-	-	-	-
3. na	"	Roosevelt	N	H	-	-	-	-	-	-	-	-	16,710	-	-
TOTAL ARIZONA				H	-	-	3,000	3,000	48,600	48,600	93,500	93,500	16,710	-	-
COLORADO															
1. Colorado Springs	Colorado Springs Dept. Utilities	Birdsall	E	GT	-	-	-	-	17,000	17,000	-	-	-	-	-
2. Gunnison River	"	Morrow Point #1 & 2	N	H	-	-	120,000 63	120,000	-	-	-	-	-	-	-
TOTAL COLORADO				GT	-	-	-	-	17,000	17,000	-	-	-	-	-
				H	-	-	),000	120,000	-	-	-	-	-	-	-
UTAH															
1. Ogden	Utah Power & Light Company	na	N	GT	-	-	'5,000	15,000	-	-	-	-	-	-	-
TOTAL UTAH				GT	-	-	_5,000	15,000	-	-	-	-	-	-	-

Table 6. The Other Plants or Units Planned or Under Construction, [illegible]-75: Hydro-Electric, Internal Combustion and Gas Turbine

CITY	COMPANY	PLANT	N-NEW E-EXISTING PLANT	TYPE OF PLANT [1]	1969 NAMEPLATE [2]	1969 DEPENDABLE [3]	1970 NAMEPLATE [2]	1970 DEPENDABLE [3]	1971 NAMEPLATE [2]	1971 DEPENDABLE [3]	1972 NAMEPLATE [2]	1972 DEPENDABLE [3]	1973 CAPACITY [4]	1974 CAPACITY [4]	1975 CAPACITY [4]
PACIFIC															
CALIFORNIA															
1. Burbank	Burbank, City of	Magnolia	E	GT	20,000	20,000	20,000	20,000	-	-	30,000	30,000	-	-	-
2. na	Calif. Dept. of Water Resources	Cottonwood	N	H	-	-	-	-	-	-	-	-	14,000	-	-
3. na	"	Devil's Canyon	N	H	-	-	-	-	-	-	117,000	117,000	-	-	-
4. Feather River	"	Oroville #4 - 6	N	H	97,750 [5]	97,750	-	-	-	-	-	-	-	-	-
5. na	"	Pyramid	N	H	-	-	-	-	-	-	172,000	172,000	-	-	-
6. Los Angeles	Los Angeles Dept. of Wtr. & Pwr.	Castaic	N	H	-	-	-	-	-	-	-	-	200,000	-	-
7. Los Angeles	"	Dry Canyon	N	H	-	-	30,000	38,000	-	-	-	-	-	-	-
8. Los Angeles	"	Foot Hill	N	H	-	-	-	-	12,000	12,000	-	-	-	-	-
9. Feather River	Pacific Gas & Electric Company	Belden #1	N	H	117,000 [4]	117,000	-	-	-	-	-	-	-	-	-
10. Sacramento	Sacramento Municipal Utility Dist.	Loon Lake	N	H	-	-	-	-	75,000	75,000	-	-	-	-	-
11. San Diego	San Diego Gas & Electric Company	Mission	E	GT	162,000	162,000	-	-	-	-	-	-	-	-	-
12. San Francisco	San Francisco, City & County of	New Moccasin #1 & 2	N	H	102,000 [64]	102,000	-	-	-	-	-	-	-	-	-
13. na	Sierra Pacific Power Company	Humboldt Valley	N	GT	-	-	1[illegible]000	15,000	-	-	-	-	-	-	-
14. Lake Tahoe	"	King's Beach	N	IC	16,500	16,500	-	-	-	-	-	-	-	-	-
15. Long Beach	Southern California Edison Co.	Alamitos #7	E	GT	138,125	121,000	-	-	-	-	-	-	-	-	-
16. Etiwanda	"	Etiwanda #5	E	GT	132,000 [5]	121,000	-	-	-	-	-	-	-	-	-
17. Hermosa Beach	"	Huntington Beach #5	E	GT	132,000	121,000	-	-	-	-	-	-	-	-	-
18. Oxnard	"	Mandalay #3	E	GT	-	-	1[illegible] 125	121,000	-	-	-	-	-	-	-
19. Long Beach	"	Pinnacles #1	N	GT	12,000	12,000	-	-	-	-	-	-	-	-	-
20. Don Pedro	Turlock Irrigation District	New Don Pedro #1 - 3	E	H	-	-	141,600 [65]	129,000	-	-	-	-	-	-	-
21. Dobbins	Yuba County Water Agency	Yuba, New Colgate	N	H	-	-	282,600	282,600	-	-	-	-	-	-	-
22. na	"	Yuba, New Narrows	N	H	-	-	[illegible] 750 [4]	46,750	-	-	-	-	-	-	-
TOTAL CALIFORNIA				GT	596,125	557,000	17[illegible],125	156,000	-	-	30,000	30,000	-	-	-
				H	316,750	316,750	520,950	496,350	87,000	87,000	289,000	289,000	214,000	-	-
				IC	16,500	16,500	-	-	-	-	-	-	-	-	-
OREGON															
1. Columbia River	Bonneville Power Administration	Lower Monumental	N	H	411,000 [66]	411,000	-	-	-	-	-	-	-	-	-
TOTAL OREGON				H	411,000	411,000	-	-	-	-	-	-	-	-	-
WASHINGTON															
1. na	Bonneville Power Administration	Dworshak	N	H	-	-	-	-	-	-	400,000	400,000	-	-	-
2. Columbia River	"	J. Day #5 - 16	N	H	959,000 [67]	959,000	411,000 [68]	411,000	274,000 [69]	274,000	-	-	-	-	-
3. Snake River	"	Little Goose	N	H	-	-	4[illegible],000 [70]	411,000	-	-	-	-	-	-	-
4. na	"	Puget Sound	N	IC	2,750	2,800	-	-	-	-	-	-	-	-	-
5. Columbia River	"	Dalles #15 - 22	E	H	-	-	-	-	258,000 [71]	258,000	344,000 [72]	344,000	86,000	-	-
6. Columbia River	PUD #1 Chelan County	Rocky Reach #8 - 11	N	H	-	-	-	-	600,000 [4]	600,000	-	-	-	-	-
7. Columbia River	"	Wells #8 - 10	N	H	323,290 [5] [73]	232,290	-	-	-	-	-	-	-	-	-
8. na	U.S. Bureau of Reclamation	Grand Coulee 3, #1-3	N	H	-	-	-	-	-	-	-	-	600,000	1,200,000	-
TOTAL WASHINGTON				H	1,191,290	1,191,290	822,000	822,000	1,132,000	1,132,000	744,000	744,000	686,000	1,200,000	-
				IC	2,750	2,800	-	-	-	-	-	-	-	-	-
	TOTAL UNITED STATES			GT	4,315,125	4,519,518	[illegible].733,185	3,880,410	1,318,400	1,385,800	30,000	30,000	10,000	-	40,000
				H	2,490,540	2,496,040	[illegible],926,150	1,904,050	2,528,366	2,531,866	2,029,833	2,029,833	4,785,085	1,868,000	75,400
				IC	154,000	156,250	[illegible],400	15,400	-	-	-	-	-	-	-

(See next page for footnotes and source.)

Table 6. The Other Plants or Units Planned or Under Construction.

1 Type of plant: GT-Gas Turbine; H-Hydro-electric; IC-Internal Combustion.
2 Maximum generator nameplate rating which appears on manufacturer's nameplate.
3 Dependable capacity of unit is the capacity which has been proven by the operating experience of the user.
4 Capacity ratings not identified as nameplate or dependable.
5 Unit(s) placed in commercial operation during first eight months of 1969.
6 Reversible pumped storage.
7 Three units at 22,900 kw.
8 Three units at 250,000 kw.
9 Three units at 16,750 kw.
10 Six units at 16,750 kw.
11 Three units at 18,600 kw. Two units placed in commercial operation during first eight months of 1969.
12 Three units at 40,500 kw.
13 Two units at 113,200 kw.
14 Eight units at 18,000 kw.
15 Two units at 15,000 kw.
16 Three units in all. Two units at 175,000 kw; both are reversible pumped storage. One unit at 30,000 kw, conventional pumped storage.
17 Two units at 18,600 kw.
18 Two units at 18,600 kw.
19 Three units at 18,600 kw. Two units placed in commercial operation during first eight months of 1969.
20 Three units at 18,600 kw.
21 Twelve units at 18,333 kw.
22 Four units at 19,000 kw.
23 Eight units at 18,375 kw.
24 Six units at 22,150 kw.
25 Four units at 18,250 kw.
26 Four units at 19,000 kw.
27 Four units at 18,150 kw.
28 Two units at 18,250 kw.
29 Two units at 37,250 kw.
30 Two units at 37,250 kw.
31 Two units at 39,400 kw.
32 Two units at 19,000 kw. Two units at 17,320 kw.
33 Four units at 18,075 kw.
34 Four units at 17,325 kw.
35 Two units at 15,000 kw.
36 Two units at 220,000 kw.
37 Two units at 17,000 kw.
38 Two units at 40,000 kw.
39 Two units at 250,000 kw.
40 Two units at 36,700 kw.

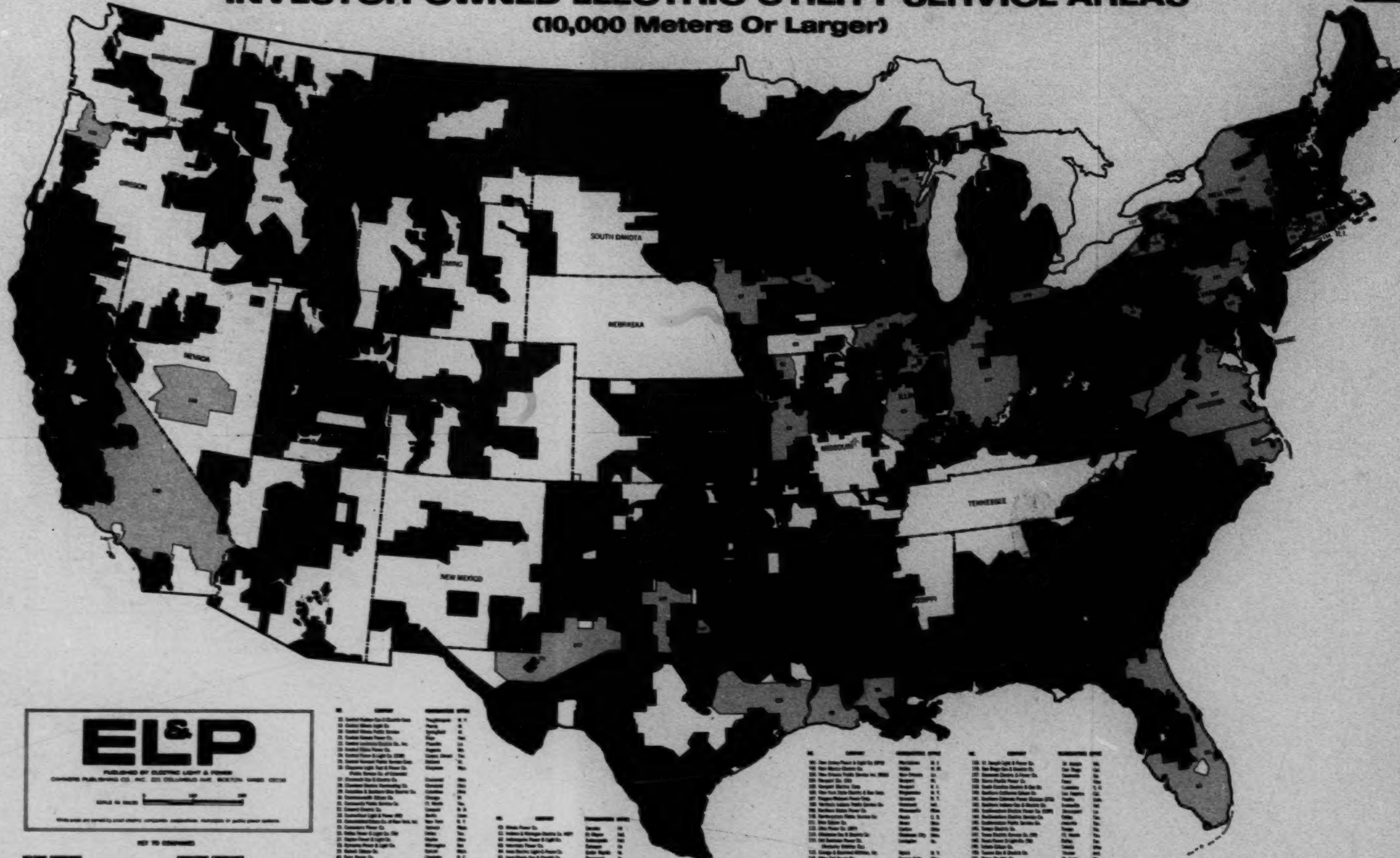
75: Hydro-Electric, Internal Combustion and Gas Turbine

41 Eight units at 16,690 kw.
42 Four units at 21,180 kw.
43 Two units at 32,640 kw.
44 Two units at 39,750 kw.
45 Four units at 36,000 kw.
46 One unit at 29,000 kw. One unit at 17,000 kw.
47 Two units at 2,500 kw.
48 Two units at 70,000 kw.
49 Two units at 20,000 kw.
50 Two units at 25,000 kw.
51 Three units at 25,000 kw.
52 Two units at 25,000 kw.
53 Four units at 17,000 kw.
54 Two units at 33,333 kw.
55 One unit at 38,000 kw, reversible pumped storage. One unit at 40,000 kw, conventional pumped storage.
56 Four units at 30,000 kw.
57 Three units at 43,200 kw.
58 Two units at 30,000 kw.
59 Two units at 27,300 kw.
60 Two units at 27,300 kw.
61 Two units at 20,000 kw.
62 Two units at 40,000 kw.
63 Two units at 60,000 kw.
64 Two units at 51,000 kw. One unit placed in commercial operation during first eight months of 1969.
65 Three units at 47,200 kw.
66 Three units at 137,000 kw.
67 Seven units at 137,000 kw. Three units placed in commercial operation during first eight months of 1969.
68 Three units at 137,000 kw.
69 Two units at 137,000 kw.
70 Three units at 411,000 kw.
71 Three units at 258,000 kw.
72 Four units at 86,000 kw.
73 Three units at 77,430 kw.

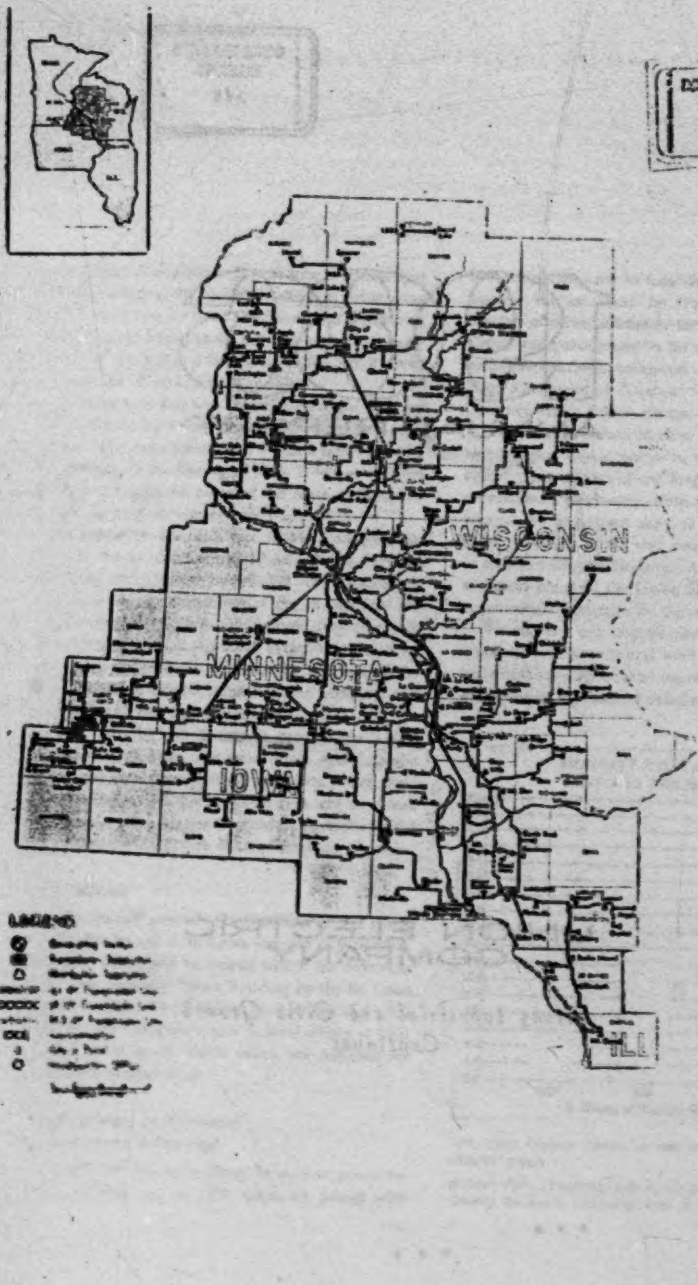
Source: Federal Power Commission Report III (data available as of Aug. 31, 1969); The Edison Electric Institute and news releases.

XXX

INVESTOR-OWNED ELECTRIC UTILITY SERVICE AREAS
(10,000 Meters Or Larger)



EL&P


WISCONSIN
MINNESOTA
IOWA
ILL
LEGEND

1966
ANNUAL REPORT

UNION ELECTRIC COMPANY

Strong Industrial and Civic Growth Continues

* * *

The Year in Review

cost of over $14 million. It will join a similar line between Minneapolis and Hills which is being completed this Spring by Iowa and Minnesota companies. This St. Louis-Minneapolis line will permit the interchange of as much as a half million kilowatts of power between the several utilities involved.

Construction also was started during the year on the Company's portion of a 345,000 volt St. Louis-Kansas City transmission line, which is expected to be in operation in the Spring of 1968. It will strengthen the power supply for much of the State of Missouri, as well as the States immediately west of us.

Transmission ties with our Ill-Mo Pool partners (Illinois Power and Central Illinois Public Service) are being strengthened by 345,000 volt interconnections and the other members of the Ill-Mo Pool are coordinating their extra-high-voltage programs with companies to the east and north to facilitate the transmission of large blocks of power in and out of the Pool. Improved system reliability and economy will result through this coordinated program.

Also, 345,000 volt lines will provide the major transmission between the new Sioux and Labadie Plants and bulk transmission substations. When these lines are completed, the St. Louis area will be almost encircled by extra-high-voltage lines to provide for the most economical delivery of large amounts of power.

New Offices

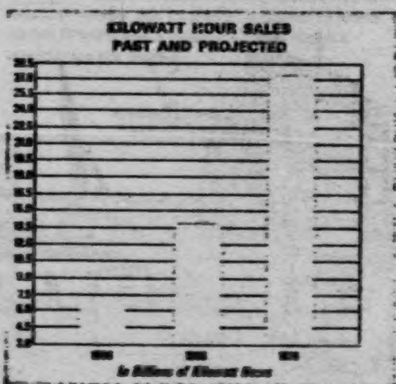
The Company's general office building at 315 North Twelfth Boulevard in St. Louis was sold in June 1966. Executive offices will be moved within the next year to the new Gateway Tower Building on the St. Louis riverfront. Other departments were moved early this year into the Company's new general offices at 1901 Gratiot Street in St. Louis which are designed for more efficient operations.

The Emphasis on Research and Improved Efficiency

Union Electric has participated in nuclear power research as long ago as 1951 when we joined with Monsanto Company in feasibility studies of a multi-purpose reactor plant. In 1953, we joined with a number of other utilities to form the Nuclear Power Group and participated in the research and development culminating in construction of the initial 200,000 kilowatt Dresden Nuclear Power unit on the Commonwealth Edison system.

We have continued in close touch with the rapid technological developments in nuclear power during recent years as part of our long range studies of the economics of producing electricity from this form of energy. An important asset to our Company is its close proximity to the vast reserves of low-cost coal in southern Illinois. However, it is quite possible that a nuclear plant on the Union Electric system will be economically attractive by the mid-1970's.

Throughout our organization there is continuing emphasis on research and work improvements. Our activities range from better use of hand tools to highly sophisticated methods of calculating and dispatching



Top, right: Queeny Tower, newest addition to the Barnes Hospital group.

Bottom, right: Christmas lights at Northwest Plaza in St. Louis County, the largest shopping center in the Midwest.

DX 147

Union Electric Company - 1967 Annual Report

* * *

A 345,000 volt interconnection with MAIN was completed in mid-1967. This high voltage tie links us directly with MAIN through our Ill-Mo Pool partners to the east. The MAIN network covers 10 states, embracing much of the Midwest and extending as far east as Virginia.

As part of our membership in MAPP, we also completed our portion of a 345,000 volt line extending from St. Louis to the Minneapolis-St. Paul area. The 250-mile Union Electric portion was constructed at a cost of $14 million, and the interconnection permits the exchange of up to 500,000 kilowatts of power. MAPP includes utilities in the states immediately west of MAIN and extends north into Canada.

Construction continued on a 345,000 volt St. Louis-Kansas City line which is scheduled for completion in 1968. This will strengthen the power supply for much of Missouri, as well as the states immediately west of us.

Union Electric's Beautification Program

The Company is engaged in a long-range beautification program to improve the appearance of its transmission and distribution lines, substations and transformers.

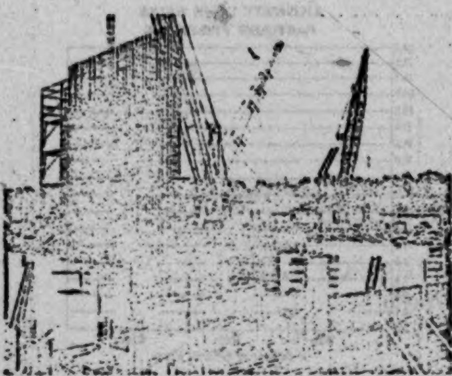
Residential underground distribution is desirable and practical in new subdivisions where the additional cost can be justified. On a system-wide basis, however, the cost of placing all lines underground would be prohibitive. It is estimated that the average residential customer's bill would have to be more than three times the present amount in order to finance the removal of all overhead lines and their relocation underground.

Our program includes the use of low profile substation equipment where possible, gray colored poles and transformers to minimize contrast, the elimination of cross arms, better looking hardware, and so on. We also make extensive use of camouflage with trees and landscaping.

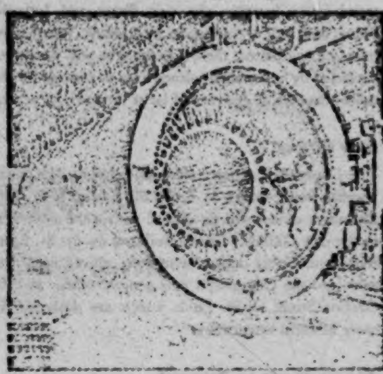
We believe there has been a considerable improvement in the appearance of our overhead facilities, and the effort is a continuing one.

Nuclear Power

As reported to stockholders in the past, the Company's proximity to vast reserves of low cost coal ideally suited for steam plant generation has heretofore given coal-fired plants an economic advantage on our system. However, we keep well informed of the rapid technological developments in nuclear power, and a nuclear plant on the Union Electric System may be economically attractive within the coming decade. In 1967 we retained the NUS Corporation of Washington, D. C., an engineering consulting organization, to assist us in evaluating nuclear plant sites in the Company's service area.



Pedestal center wall for Labadie's No. 1 turbine generator.



Labadie Plant's generator, being built in East Pittsburgh, Pa.

4

* * *

DX 148

Union Electric Company - 1968 Annual Report

* * *

The challenge/expansion

north, east, and west through extra-high-voltage lines.

Union Electric is a member of two of the nation's largest power planning groups—MAIN (Mid-America Interpool Network), operating in the Midwest and extending east into Virginia, and MAPP (Mid-Continent Area Power Planners), operating in the states west of MAIN and extending north into Canada.

The plans of both groups are being implemented very effectively. For example, when the huge MAPP system was formed five years ago, its member utilities planned 5,400 miles of EHV lines to be completed by 1980. As of year end 1968, more than 2,500 miles were completed and the network is now expected to be nearly complete by 1972. MAPP members already are planning to build another 5,000 miles by 1980 to create an over-all, interconnected extra-high-voltage grid of 10,400 miles.

Research and Development

Research and development programs at Union Electric— the constant probing for new devices, new methods—are basic to providing reliable electric service to our customers at lower cost and to improving the Company's contributions to the community in environmental control.

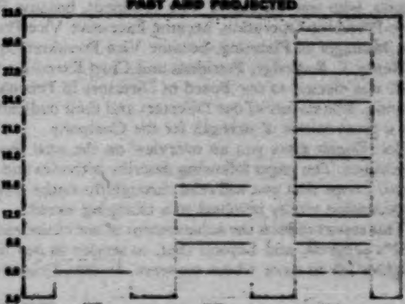
A highlight of the year was the $1 million installation at the Company's Meramec Plant of the nation's first full-scale system for the removal of sulfur dioxide from the stack emission of a coal-fired steam generator—a research effort that will produce significant progress in air pollution abatement technology. At year end, after a three-month "break-in" period, the installation was removed from service for design modifications. It is now back in service with improved performance. This system, which was designed and installed by Combustion Engineering, Inc. was named one of the "engineering achievements of 1968" by the National Society of Professional Engineers.

In a related project, Union Electric engineers have been working to improve sulfur dioxide air monitoring equipment at eight stations which the Company has placed in service around the Sioux and Labadie plants. Data from these stations, along with data from stations operated by governmental authorities, will form an air quality measuring network for the St. Louis area.

As another aspect of environmental control, the Company is engaged in a long-range program to improve the appearance of its poles, lines, substations and transformers.

Union Electric also participates in numerous cooperative research programs with its manufacturing suppliers and with industry groups. One of the most interesting at present is the work of Gulf General Atomic, Inc. on the gas-cooled fast breeder nuclear plant concept, a project in which Union Electric and a number of other electric companies are partners.

KILOWATT HOUR SALES
PAST AND PROJECTED



In Billions of Kilowatt Hours

* * *

DX 149

Northern States Power Company - 1968 Annual Report

* * *

Although it was unfortunate that the Pathfinder nuclear reactor had to be prematurely retired at some considerable loss to the Company, the experience and know-how of our engineering and operating staff in the field of nuclear power has been extremely beneficial to us in connection with our major new nuclear projects. We feel also that the presence of nuclear power as a competitor has assisted us materially in controlling the costs of fossil fuels.

While managing our day-to-day operations and performing our jobs, we at NSP hold a vision of the future that inspires and challenges us. We see tremendous opportunities in the areas of climate control, transportation, improvement in the environment and living conditions. Imagine domed downtown areas and shopping complexes where the climate is electrically controlled the year around. Home computers will program and direct meal preparation. This is the high-energy society of tomorrow in which electric energy will bring us to new levels of comfort and achievement.

Projections show that all this will mean large increases in business for NSP. Our forecasts indicate that sales of electricity for the year 1972 will total more than 16 billion kilowatt-hours, compared with 12.5 billion kilowatt-hours in 1968. Projecting further, we anticipate that our total Company maximum demand for electricity will rise to more than 13 million kilowatts by 1990, compared with 2.7 million kilowatts in 1968.

As we move into this high-energy era, we are doing everything possible to build and operate our electric facilities so that they will make a minimum impact on the environment. NSP is in the forefront of air pollution control and abatement and will utilize emerging technology to further improve air quality. We are using the most modern design and equipment available to maintain water quality at our generating plants and are conducting continuing studies to assure that nature's balance is maintained. We are drawing on years of research by the Atomic Energy Commission and on the experience of NSP and other utilities to make certain that nuclear power plants present no danger to health and welfare.

In November, NSP and Minnesota Power & Light Company jointly announced the termination of negotiations concerning a possible corporate affiliation between the two companies. As discussions developed, it became clear that this was not a propitious time for an affiliation.

Among your management's most important responsibilities are the development of talent in the organization and constant evaluation of our personnel structure to meet NSP's changing and expanding needs. The broadening scope of our business brought management changes in May, 1968. Allen S. King, who had been Chairman of the Board since his retirement from active service in 1965, was elected Chairman Emeritus. I became Chairman of the Board and will continue as Chief Executive Officer. R. H. Engels, who was Executive Vice President, became President. E. A. Willson, formerly Vice President-Operation, became Executive Vice President, and D. W. Angland, who was Manager of Planning, became Vice President-Operation.

Henry T. Rutledge, President and Chief Executive Officer of Northwest Bancorporation, was elected to our Board of Directors in February, 1968, succeeding Kenneth N. Dayton. The stature of our Directors and their dedication to NSP's corporate citizenship are a great source of strength for the Company.

Bob Engels gives you an overview on the next few pages of the results of our 1968 operations. The pages following describe activities and accomplishments in more specific areas. I hope that you will read through the entire report, because it tells the story of an organization vitally involved in a changing world.

This report reflects the achievement of our entire employee force. We are dedicated to NSP's progress, and beyond that, to service to our fellow man. Our job is to bring a brighter life to those whom we serve. In that I sincerely believe we are succeeding.

Sincerely, Earl Ewald

* * *

Record demands by NSP's customers in 1968 called for an all-out effort by the Company's operating and construction forces. A winter maximum demand in power use was set at 2,319,782 kilowatts in January. But this winter record was easily broken early in the summer and four successively higher maximum demands were set as the summer wore on. Finally, the year's record was set August 23 at 2,701,359 kilowatts, a 16.3 per cent increase over the 1967 maximum demand of 2,323,383 kilowatts. At the time of the summer maximum demand, NSP was purchasing 196,000 kilowatts of capacity.

Good planning met needs

NSP had anticipated that kind of demand when planning was started more than four years before on the 580,000-kilowatt Allen S. King generating plant. The King plant

Feeding a thriving, power-hungry area

went into service well ahead of the 1968 summer demand, taking on its shoulders about 20 per cent of the Company's maximum demand. Smaller generating plants, recently built especially to help carry the load in peak times, also did their share in assuring NSP's traditionally dependable power. A 5500-kilowatt diesel generating plant at Albany, Minnesota was ready for winter peak duty in the fall. The Company started building a 69,000-kilowatt gas-turbine electric generating plant for peaking purposes at St. Cloud, Minnesota in 1968 which will be ready for service in May, 1969. A similar installation will be started in 1969 at Mankato, Minnesota to be completed by the spring of 1970.

The Company also announced plans to build a large generating plant on the Minnesota river near Jordan, Minnesota—not far from the Twin Cities—sometime in the late 1970's. The Company has been taking steps toward acquisition of a 2100-acre site in the area. No decision has been made yet on the size of the plant or choice of fuel.

'68 water power well above average

It was a good year for NSP's hydro-electric operations too, cutting NSP's power production expense. The Company's hydro plants turned out 7 per cent of the total energy generated by NSP during the year. This kilowatt-hour production was 25 per cent higher than our 20-year average annual hydro output.

Pathfinder to be converted to gas fuel

The Company made the decision in 1968 to convert the Pathfinder plant near Sioux Falls, South Dakota from nuclear fuel to gas fuel. The gas-fired boilers are now being installed at the plant so that the Pathfinder facility will be ready to generate 70,000 kilowatts of power by summer, 1969.

The Pathfinder nuclear plant had been shut down since September, 1967 because of mechanical problems associated with the reactor. Repairs and modifications necessary to resume nuclear operations would have cost as much as constructing the new gas-fired boilers and could not have been completed by the time power was needed from the plant in 1969.

As a result of the decision to terminate the nuclear portion of the Pathfinder plant, $9.5 million will be written off over a 10-year period. Contractual and technical aspects of the Pathfinder nuclear project are being reviewed by NSP with the contractor, Allis-Chalmers Manufacturing Company, and regulatory aspects of the plant are being reviewed by the Atomic Energy Commission.

E. A. WILLSON
Executive Vice President

● Construction is on schedule at NSP's Prairie Island nuclear generating plant, where these workmen are installing a stat-lining cable for the construction derrick. The 200-foot-high cement "silo" will house the nuclear reactor for the first 550,000-kilowatt generating unit.

Nuclear generating plant construction on schedule

Construction continued on schedule at NSP's 545,000-kilowatt nuclear generating plant at Monticello, Minnesota due for service in 1970. Public hearings were held in May by the Atomic Energy Commission on NSP's Prairie Island plant near Red Wing, Minnesota. Then, when the AEC granted its approval for that 1,100,000-kilowatt plant in July, construction activity picked up immediately. Completion of the first 550,000-kilowatt unit at Prairie Island is set for 1972 . . . the second for 1974.

Transmission lines will deliver power where needed

Many high-voltage transmission lines to speed power today and tomorrow to where it is

* * *

NATIONAL POWER SURVEY

A REPORT BY

THE FEDERAL POWER COMMISSION

1964

FEDERAL POWER COMMISSION

U.S. Government Printing Office
Washington : October 1964

For sale by the Superintendent of Documents, U.S. Government Printing Office
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CHAPTER 3

FUELS AND FUEL TRANSPORT FOR ELECTRIC ENERGY

The electric power industry uses more than half of all the bituminous coal mined in this country, large volumes of natural gas and oil, and a growing amount of nuclear energy.

Fossil fuels were the basic energy source of 81 percent of the electricity generated in the United States in 1963. In order to meet the tremendous growth in the demand for electricity expected for the coming decades, our projections indicate that by 1980 the electric power industry will more than triple its 1960 demand for fossil and nuclear fuels and will be using annually some 500 million tons of coal, 4 trillion cubic feet of natural gas, 100 million barrels of residual oil, and 20 to 30 thousand tons of uranium for nuclear generation.

Fuel accounts for 15 cents of every dollar spent by utilities for electric power, with transportation comprising a significant part of the total fuel cost. The future demands for fossil and nuclear fuels involve such large quantities that competition and technological gains will most certainly result in reducing the cost of fuel at the source, and also the cost of moving it to market. Delivered fuel costs are expected to drop from a 1962 average national price of 26 cents per million British thermal units to 21 cents by 1980. These figures reflect anticipated reductions in fuel transportation costs and in some cases, the alternative of locating power plants at the fuel source and transmitting the electricity, rather than the fuel, to the load area.

This chapter reviews the major considerations affecting the supply and costs of fuels to electric utilities during the survey period. In making our appraisal of fuel supply and costs, we have drawn heavily on basic general energy studies conducted in recent years by Government and private sources and especially upon the reports submitted to the Commission by the Special Technical Advisory Committee on Fuels.

Total Fuel Requirements

The total use of fossil and nuclear fuel for electric power generation is projected to increase from 6,500 trillion Btu in 1960 to approximately 22,000 trillion Btu in 1980. The latter figure is equivalent to 900 million tons of coal with a heat content of 12,500 Btu per pound. The rate of increase of use for fuels projected by the electric power industry closely parallels the rate of growth we have projected in the National Power Survey; for 1980 both the loads and the fuel requirements are approximately 3⅓ times the 1960 level. Although the share of thermal sources (including nuclear) is expected to increase to 87 percent of total kilowatt-hours generated in 1980 as the share of hydroelectric power declines, continued progress in reducing fuel requirements per kilowatt-hour should offset the impact of the increased reliance on thermal sources.

The estimated total fuel requirements for thermal power generation, including nuclear fuel, by study areas is presented in table 20. These estimates reflect the reduced fuel requirements per kilowatt-hour of using the larger generating units with improved thermal efficiencies. The trend in fuel used in the typical area tends to follow the expected growth in the area's electrical loads. The major departures from this pattern occur in several areas of the Far West—L, N, O and especially P. These areas at present depend on hydroelectric sources for a major share of their generation but will become increasingly dependent on thermal sources for future growth as the availability of good undeveloped hydro sites diminishes. Some areas, of course, are expected to be moderate net importers or exporters of electricity generated at particularly favorable locations, including some mine-mouth alternatives and Canadian hydro. These sources are examined in chapter 15. The expected growth of fuel requirements therefore does not always coincide with the expected growth in load.

Fuel Availability and Use Trends

The overall outlook for fuel availability is favorable. We expect fuel supplies at prices close to present levels to be ample to meet the thermal electric demand for the life of generating plants installed by 1980.

TABLE 20

Fuel Requirements for Thermal Power Generation by Coordination Study Areas (See Fig. 19)

(Trillions of Btu)[1]

	Coordination study area[2]	1960 actual	1970 estimated	Percent increase 1960-70	1980 estimated	Percent increase 1970-80	Percent increase 1960-80
A	New England	286	530	85.3	900	69.8	214.7
B	New York	444	842	89.6	1,408	67.2	217.1
C	Pennsylvania-New Jersey-Maryland	658	1,057	60.6	1,716	62.3	160.8
D	Ohio Valley	1,156	2,124	83.7	3,489	64.3	201.8
E	Carolinas-Virginia	296	630	112.8	1,246	97.8	320.9
F	Tennessee Valley	469	837	78.5	1,390	66.1	196.4
G	Southeastern	447	1,019	128.0	1,931	89.5	332.0
H	Lower Michigan	252	498	97.6	908	82.3	260.3
I	North Central	872	1,526	75.0	2,608	70.9	199.1
J	Texas Area	348	772	121.8	1,219	57.9	250.3
K	Middle South Area	478	794	66.1	1,246	56.9	160.7
L	Upper Missouri Basin	66	106	60.6	234	120.8	254.5
M	New Mexico and Panhandle	86	158	83.7	252	59.5	193.0
N	Southwest	577	1,093	89.4	2,270	107.7	293.4
O	Colorado-Wyoming Area	71	127	78.9	248	95.3	249.3
P	Northwest	34	50	47.1	642	1,184.0	1,788.2
	Contiguous United States	6,540	12,163	86.0	21,707	78.5	231.9

[1] Includes nuclear as well as conventional thermal plants. Btu requirements for nuclear generation are estimated on the basis of the average heat rate for conventional steam.

[2] Excludes Alaska and Hawaii.

Source: Advisory Committee Report No. 21, prepared by the Fuels Special Technical Advisory Committee, Appendix 1, p. 315, Part II.

Table 21 compares the kilowatt-hours generated from each of the major energy sources in 1963 with estimates for 1980. The actual 1980 figures, and the market shares they imply will, of course, depend on the many hard-to-predict factors which affect interfuel competition. Whatever the precise shares turn out to be, it is clear that each of the fossil fuels will continue to supply both increasing amounts and an important share of a growing market, even though, as the table indicates, the percentage shares of the fossil fuels are expected to decline as a result of important nuclear fuel competition.

Coal, which presently supplies more than half of the market, will continue to be the workhorse for electric generation throughout the survey period, although its percentage share will decline from 54 percent to 47 percent, while natural gas should remain dominant in areas near sources of gas supply, although it can expect increasingly stiff competition elsewhere and on a nationwide basis its share will also decline from the 21 percent of 1963 to 17 percent of 1980. Oil will, in all likelihood, remain confined to coastal areas having access to cheap water transportation, where its share will depend to a large extent on the availability of imports at competitive prices. Overall, it is expected that oil, while more than doubling its volume, will decline on a proportionate basis by a third, from 6 percent to 4 percent of the market. Nuclear fuel will skyrocket from negligible current use to about 19 percent of the 1980 market.

Interfuel Competition

The choice between competing fuels depends not only on delivered prices but on many other factors

TABLE 21

Energy Sources for Generation

	1963		1980	
	Billion kwh	Percent of total	Billion kwh	Percent of total
Coal	494	54	1, 264	47
Natural gas	201	21	458	17
Oil	50	6	107	4
Total fossil fuel	745	81	1, 829	68
Nuclear	3	0. 1	514	19
	748	81	2, 343	87
Water power	166	19	340	13
Total	914	100	2, 683	100

as well, including the relative thermal efficiencies of different fuels and differences in capital costs of generating plants equipped to burn particular fuels. The following statement by the Fuels Committee sums up some additional considerations:

> In determining the type of fuel to be used for electric generation, there are a number of factors to be reviewed and evaluated. Each of these has a bearing on cost and influences the degree to which an electric utility is able to meet its obligation to provide reliable service at a reasonable price. The costs of storing, handling, and in some instances, disposing of the fuel product are economic factors which can make a low-cost fuel the most expensive fuel. In locations where land costs are high and areas heavily congested, these costs become a major consideration in selecting a proper fuel. In some areas, operating conditions, such as air control regulations on the West Coast, may justify a premium fuel. Therefore, while a general picture can be drawn concerning the availability and price of fuels, the final determination in selecting a fuel or fuels for a particular plant must be based on the specific facts pertinent to that plant and its location.[1]

Relative delivered price per Btu is usually the overriding factor in competition among the fossil fuels. The choice of fuel is an integral part of the selection of a plant site but often competition between fuels may occur after a plant is in operation. Many stations are initially designed and equipped to burn alternative fuels interchangeably upon short notice, and stations originally designed for coal can usually be adapted to use gas or oil. Likewise, some gas or oil-burning plants can be adapted to use coal, but unless the plant was originally designed with this in mind, the conversion may be expensive. In many locations the competing positions of alternative fuels are very close, and a price reduction for any one fuel may trigger competitive reductions in other fuel prices.

While the fuel with the lowest delivered cost usually sets the pace for competition, the delivered prices at which fuels become competitive are not always identical. For instance, a coal-burning plant typically requires 10 to 15 percent more capital investment—chiefly in coal and ash handling equipment and more expensive boiler design—than a comparable plant which is not so equipped. However, this differential has a significant effect on interfuel competition only where gas and oil supplies are adequate to serve the plant's entire fuel requirements throughout its service life. Thermal efficiencies, which vary between different grades of the same fuel as well as between different fuels, also affect the relative prices at which fuels are competitive. Coal typically requires some 3 to 5 percent fewer British thermal units per kilowatt-hour than gas, with oil occupying an intermediate position.

[1] Advisory Committee Report No. 21, p. 317 of Part II.

Interfuel competition is expected to intensify in the future, particularly in the higher fuel cost areas, where improvements in energy transportation and the reductions in the costs of nuclear power should bring fuel costs closer to those of the lower fuel cost areas. Just as nuclear technology is shooting at a continually moving target in attempting to overtake conventional steam-electric generation, nuclear technology in turn is expected to set a continually lowering cost target which the fossil fuels and their modes of transport will be forced to meet.

Coal

Widely varying assessments of coal supplies are available depending upon the purpose and the nature of the investigations. The most recent official Department of the Interior estimate for all types of coal is that "recoverable reserves" in the continental United States, excluding Alaska, amount to 830 billion tons.[3] By comparison the projected energy requirements for thermal electric generation for the year 1980 is equivalent to 900 million tons of coal, of which nearly 500 million tons are expected to be in the form of coal.

The estimates of coal reserves can be misleading. While total reserves are more than adequate to meet any foreseeable demands by the electric utility industry, extensive tracts of coal lands adapted to low-cost mining techniques are by no means unlimited. A better inventory of our low-cost coal reserves than is now available would be of great value in industry planning.

The wide distribution of coal reserves throughout the United States is shown in figure 27 which depicts the "recoverable reserves." It is not generally realized that more coal lies west of the Mississippi River than to the east, although some 60 percent of the higher bituminous grades are found east of the Mississippi. While the western coals can be mined at low cost, they have not been extensively exploited to date, because of their distance from major load centers. Later chapters in the National Power Survey explore the possibilities of utilizing the abundant low-grade coals in the west.

Coal costs and prices at the source vary greatly with geologic conditions, methods of mining, required degree of quality control and many other factors. In order to determine the at-source coal

[3] Advisory Committee Report No. 21, p. 319 of Part II.

FIGURE 26 *A twin borer continuous mining machine moves between working places in a West Virginia coal mine. These massive and costly machines typify the bituminous coal industry's drive to hold or reduce the price of coal in the face of rising costs. This machine rips coal from the face of the seam and passes it back to the conveyor belt or shuttle cars at a rate of up to 8 tons a minute, eliminating the separate operations of cutting, drilling, blasting and loading.*

prices for large volume utility coal customers, the Fuels Advisory Committee enlisted the cooperation of 20 selected electric systems which purchased over 45 percent of all coal used by electric utilities in 1961. The average price f.o.b. the mine paid by these systems ranged from 12⅓ cents to 16⅓ cents per million Btu and averaged 15 cents per million Btu. 1961 prices in the several coal-producing districts are shown in the Advisory Committee's report.[4]

Coal-mining productivity has more than doubled in the past decade from an average of 7.5 tons per man-day in 1952 to 15.4 tons per man-day in 1962, an almost unprecedented productivity improvement for a mature industry. This represents an accelerated rate of improvement over prior years which, if continued, augurs well for the future competitive position of the coal industry. Continued mine mechanization including the use of large shovels such as the one shown in figure 28, more intensive mining machine utilization, improved haulage systems and the development of mines designed specifically to supply the electric power market are factors operating to lower future coal costs at the mine. Mining conditions, changes in wage rates and the costs of competitive fuels can also alter future prices at the mine.

[4] Advisory Committee Report No. 21, p. 351 of Part II.

DISTRIBUTION OF FOSSIL FUEL RESERVES

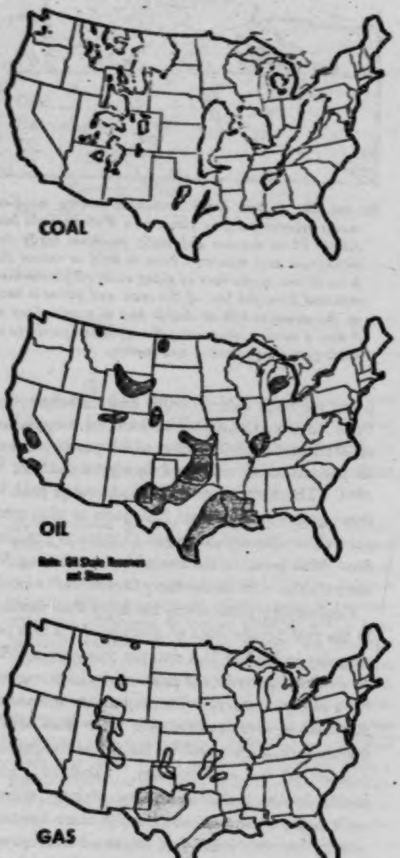


FIGURE 27

In general, the outlook is for stable to moderate reductions in the f.o.b. mine prices with further lowering in delivered costs through broad application of volume movements by highly efficient rail and other transport facilities.

FIGURE 28 Huge machines, such as this electric powered 115 cubic yard strip shovel, operated by the Peabody Coal Company in its strip mines near Paradise, Kentucky, are contributing to the continued reduction in the cost of mining coal.

FIGURE 29 Coal storage yards at coal-burning steam-electric plants contain 4 to 6 months reserve supply of fuel. The stockpile is placed in layers and compacted to prevent spontaneous combustion. The storage yard is equipped with an extensive system of conveyor belts for unloading, stocking and delivering coal to bunkers.

Natural Gas

Proven recoverable reserves of natural gas in continental United States, excluding Alaska, approximated 276 trillion cubic feet at the beginning of 1964, equivalent to about 11 billion tons of high

grade bituminous coal and enough to last about 19 years based on 1963 net production of 14.7 trillion cubic feet. The proven reserve figure, however, is a conservative estimate of the reserves already discovered which can be appraised with a high degree of accuracy, and which are recoverable under current economic and operating conditions. There is no comparable estimate of coal reserves.

Estimates of the additional gas that may ultimately be discovered and produced range from 2 to 10 times the 1964 proven reserves of 276 trillion cubic feet. In addition, we are already importing gas from Canada which has 36.7 trillion cubic feet of proven reserves and there is an immense potential for the discovery of additional gas reserves in that country. Alaska, where exploration has just begun, already has an additional 1.7 trillion cubic feet of proven reserves.

Natural gas reserves are heavily concentrated in five States—Texas, Louisiana, Oklahoma, Kansas, and New Mexico (see fig. 27). This contiguous area accounts for over 88 percent of proven reserves in the continental United States excluding Alaska. While the Geological Survey estimates that most of the United States is favorable for the discovery of natural gas and oil reserves, it is expected that the major portion of new reserves to be found and developed between now and 1980 will be in or near the areas in which reserves have already been found.

Electric utility consumption of natural gas has increased at an average annual rate of 11½ percent during the past three decades. This extraordinary growth reflects the dynamic growth of the natural gas industry, especially since World War II as the extension of natural gas pipelines from the major gas producing areas to every State in the Union other than Maine and Vermont has made natural gas available in many new markets throughout the country. Electric utility purchases, frequently under contracts which provided that service could be interrupted when the pipeline required the gas to serve other customers, contributed to the economic feasibility of pipelines by providing markets in the summer and other periods when residential gas demand is not at its highest and by helping justify the installation of larger and more economical pipelines than would otherwise be needed in advance of growth in residential demand.

During the most recent decade, 1953–63, natural gas consumption for electric generation has increased at an annual rate of approximately 7.5 percent, with the share of total thermal generation supplied by natural gas increasing from 24 to 27 percent during the same period. Large scale extensions of pipelines to new areas continued to be important during the past decade as, for example, in California, where electric utility consumption of natural gas, the local supply being augmented by new pipelines from the Permian and San Juan Basins of Texas and New Mexico, more than tripled. New pipelines were also a factor in the West Central Region (FPC Region VI), the second most important growth area. Another significant factor influencing gas consumption in both areas has been a sharp increase in the share of total generation supplied by fuel burning steam plants and the corresponding decline in the portion of total loads supplied by hydroelectric power. Natural gas is now available in 46 of the 48 contiguous States, and in 43 of these gas is used to some extent for electric generation.

Table 22 presents projections of future electric utility gas consumption developed by the Commission's Bureau of Natural Gas in cooperation with the Fuels Advisory Committee. The projection of 4 trillion cubic feet of gas for electric generation in

TABLE 22

Consumption of Natural Gas by Electric Utilities
(Trillions of cubic feet)

FPC Regions	Actual 1960	Estimated 1970	Estimated 1980
I, II and III plus Illinois and Wisconsin[1]	0.33	0.30	0.30
IV and VI less Illinois and Wisconsin[2]	0.20	0.41	0.77
V (South Central Region)	0.81	1.55	2.16
VII and VIII (Northwest and Southwest Regions)	0.39	0.74	0.83
Total	1.73	3.00	4.06

[1] (Northeast, East Central and Southeast Regions plus Illinois and Wisconsin.)

[2] (North Central and West Central Regions less Illinois and Wisconsin.)

1980 is twice the 1962 usage. A detailed account of the basic assumptions and analyses underlying the projections appears in the report of the Fuels Advisory Committee No. 21, p. 315 of Part II.

FIGURE 30 *A link in America's network of major natural gas pipelines is coated and wrapped for extra protection against corrosion before it is placed in the trench. The 190,000-mile network provides the nation with a transport system for the economic supply of natural gas to many areas and for many purposes including its use as primary or interruptible fuel for steam-electric generating stations.*

The projections of future gas consumption by electric utilities, table 22, are based purely on market trends. These projections do not reflect any policy decisions by the Federal Power Commission on the use of gas for boiler fuel and are not intended to imply any prediction of future Commission policy in exercising its regulatory responsibilities in this area.

In table 22 Illinois and Wisconsin are grouped with FPC Regions I, II, and III because they are similar to the other States in those regions in their predominant use of coal as fuel for electric generation. In those areas, it is expected that most of the gas used for future electric generation will be on an interruptible basis. Competition from coal and from nuclear fuels and the expiration of old low-priced gas contracts are likely to prevent a significant net increase in electric utility gas consumption in this section of the country.

Region VI, and the portion of Region IV west of the Mississippi, represent a mixed fuel area with varied competitive situations and generally low delivered gas costs. Gas is projected to maintain its share in this area. The major market for fossil fuels in the Far West (Regions VII and VIII) is in Region VIII which includes California, Arizona, and Nevada, a high fuel cost area in which gas is now the dominant fuel for generation. The projected slowdown in the growth of the boiler fuel market during the 1970's largely reflects the expectation of nuclear competition.

In Region V—the South Central Region—which includes over 90 percent of the Nation's known gas reserves, gas has a substantial competitive edge. However, some load centers are closer to deposits of coal or lignite than to the closest gas fields, and the economic attractiveness of these competitive sources is increasing. The projection for Region V assumes that gas will be the source of 80 percent of the total generation in the region in 1980, and that more than half of total boiler fuel sales of gas will be concentrated in this region.

Interfuel competition, primarily with coal, is expected to limit increases in the cost of natural gas for electric generation to about the present levels in most sections of the country. In the gas producing areas, however, natural gas enjoys a substantial current price advantage with respect to other fuels and thus could increase in price without materially affecting its competitive position. Comparison of the present price of gas in any particular location with limiting prices of competing fuels provides a rough measure of the extent to which the price of gas for power production has room to increase.

Oil

Residual oil, the only fuel oil used in significant quantities for electric generation in the United States, is an oil refinery byproduct which remains after the more valuable refined liquids have been extracted and solids have been removed. Since it is a byproduct, residual oil is supplied in amounts which depend primarily on the market for other refined oil products. Residual is only a small proportion (9.6 percent in 1962) of the total barrels of refined oil products produced domestically, and

nearly one-half of U.S. residual oil consumption is supplied by imports. The availability and price of imported residual depends on U.S. import restrictions as well as the world supply and demand for petroleum products.

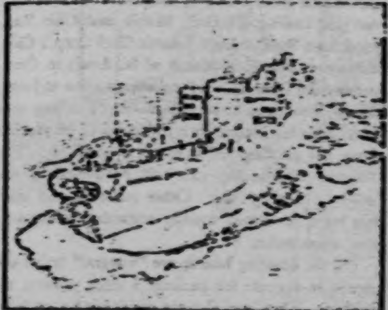


Figure 31 This ship, typical of the modern super-tanker, which carries crude oil to Atlantic Coast ports from southwestern producing areas and crude and residual oil from foreign ports, has a cargo capacity of 66,000 long tons and a draft fully loaded of 42 feet. Refinery residual oil is used extensively as fuel for steam-electric plants along the Atlantic, Gulf and California coasts.

Residual fuel oil finds its market along the east and west coasts together with some of the areas bordering the major inland waterways. Residual oil can compete with other fuels only where waterborne transport is available. In much of this area, however—especially in the northeastern United States—it provides a competitive influence that would not otherwise exist and thus operates to reduce prices of other fuels to the benefit of the consuming public. Residual oil is purchased by the barrel and a barrel roughly equals one-fourth of 1 ton of coal in heat equivalent. The current average price is approximately $2.10 a barrel, the equivalent of 35 cents per million Btu. In 1962, residual oil was used to produce about 7 percent of total thermal electric generation, but it constituted 27 percent of the fuel used for generation in the Northeast (FPC Statistical Region I).

U.S. import policies are an important factor in the consumption of residual oil by electric utilities as well as other users. A policy of easing import restrictions could be expected to intensify interfuel competition and possibly expand the area within which residual oil competes with other fuels. The effect upon the use of other fuels would depend upon the ability of the various fuels to counter residual's lower price. The overall merits of such a policy depend on complex considerations involving many aspects of the national interest which are beyond the scope of this Survey. The dependence of residual oil availability and price on our international and domestic policies and on world oil markets sets this fuel apart from the other fossil fuels in that it is less amenable to accurate projection based on normal reserve calculations and economic and technological factors. Our projections that residual oil will supply a somewhat smaller share of the market in the future reflect the possibilities of appreciable reductions in the cost of using coal and nuclear energy.

Nuclear

According to the Atomic Energy Commission "reasonably assured resources" of uranium and thorium have a total energy content of more than 94,000 Q [4] but with the existing technology of mining and concentrating nuclear materials only 3/10,000 of this total or 28 Q, could be mined at current cost levels. For comparative purposes, the annual basic energy consumption of the United States (coal, oil, gas and hydro) is about 0.05 Q and recoverable fossil fuel resources are estimated at 15 to 20 Q [5] but may be much higher. Of this amount, perhaps 6 Q is available at current costs.

While the estimate of 28 Q of nuclear fuel represents a very large reserve, the discussion of nuclear fuel resources can be misleading unless we consider the low efficiency with which nuclear fuel is now utilized and the prospects for improving that efficiency. Present reactors utilize nuclear energy with an efficiency of only about one percent of the potential energy in nuclear fuel. As a practical matter no energy is presently realizable from thorium reserves (about 6 Q of the 28 Q). In total,

[4] A "Q" is a billion billion (10^{18}) Btu, and corresponds to the heat content of about 40 billion tons of high grade coal.

[5] Total recoverable coal reserves for the continental United States excluding Alaska are estimated at 830 billion tons, equivalent to about 16 "Q", but this assumes only 50 percent recovery. Proven oil and gas reserves estimated on a much more conservative basis represent about 1 "Q".

the nuclear energy obtainable with present technology from uranium minable at about current costs thus represents less than one Q rather than 28 Q. While this is only a portion of the ultimate nuclear potential, it is still several times as large as the projected use (at existing efficiencies) of nuclear plants built during the survey period and the technology can be expected to make much larger reserves available during this time. A further discussion of nuclear fuel reserves and the effects of high converter and breeder reactors on more efficient use of these resources is contained in chapter 5.

Fuel Transport Cost

Important reductions are being made in the transportation costs of all fossil fuels but the most impressive developments in recent years and in prospect for the near future relate to the transportation of coal. Further, transport costs account for a much larger proportion of the delivered fuel costs for coal than for natural gas and oil. For these reasons the following discussion of transportation costs is largely related to the movement of coal.

Railroad Transport

Coal is the largest single item of railroad traffic. Three-quarters of all coal tonnage shipped in 1962 utilized rail transport for part or all of the movement from mines to consumers. Coal shipments represent close to 40 percent of the freight tonnage and produce about 25 percent of the revenues of Eastern District railroads, which serve the major coal fields east of the Mississippi River.

After World War II, railroad freight rates on coal increased and the total tonnage of coal shipments by rail began to decline. In the late 1950's, the railroads reversed this trend of rate increases and began to adopt low rates for volume movements in an effort to increase tonnage. More recently, the railroad industry, with the approval of regulatory agencies, has adopted still lower "trainload" rates and in cooperation with electric utilities has been exploring new coal transport arrangements to lower costs and effect major reductions in rates for large movements of coal. Increasing competition from barge lines, the perfection of coal pipelines and the emergence of nuclear energy as an added competitor have been major factors spurring railroad action to reduce rates.

An important new development is the "unit" train operating between a single mine and a single generating plant with special equipment and tight scheduling of loading, unloading and movement, and often employing utility owned coal cars. A recent example of such an arrangement is the 126-car shuttle train which in October 1964 will start carrying coal on the Gulf, Mobile and Ohio Railroad from Southwestern Illinois Coal Corp.'s Captain mine located southeast of St. Louis to Commonwealth Edison Co.'s generating station at Joliet, Ill., a distance of about 300 miles. The new rate of $1.30 a ton represents a reduction of 49 percent from the existing rail-barge rate of $2.56. The 100-ton swivel-dump cars will be owned by the utility. (See fig. 32.) Other railroads and utilities have developed equally attractive transportation movements.

On the drawing boards are "integral" trains designed to operate for perhaps a week without refueling. The integral train consists of very large cars permanently coupled to power units interspersed among the cars. The cars are designed for rapid automatic unloading and are insulated and heated to avoid the problem of frozen coal. Integral trains will operate at passenger train speeds with remote control of all features from the head of the train. Train capacity would be about 35,000 tons in contrast to today's big trains of 7,000 to 10,000 tons. A control car at each end of the train would permit shuttle service without the necessity for turning at either end of the run. A key factor in the integral train's economy is its short "turn around time" from loading at mine to unloading at power plant and return, with major savings in the fixed charge component of cost.

The availability of sharply reduced freight rates for large volume movements of coal to steam generating plants has added a new and very large additional element of savings realizable in providing generating capacity in large units and stations. Larger generating units are more efficient and less costly per kilowatt in themselves. But the savings in coal transportation rates from the volume movements they make possible provide additional savings which are perhaps just as large or in some cases even larger than the savings in the cost of generation.

Volume movements and improved techniques of coal transportation can be expected to permit substantial reductions in railroad rates for coal by 1980. Figure 33, based on the study by the Fuels Com-

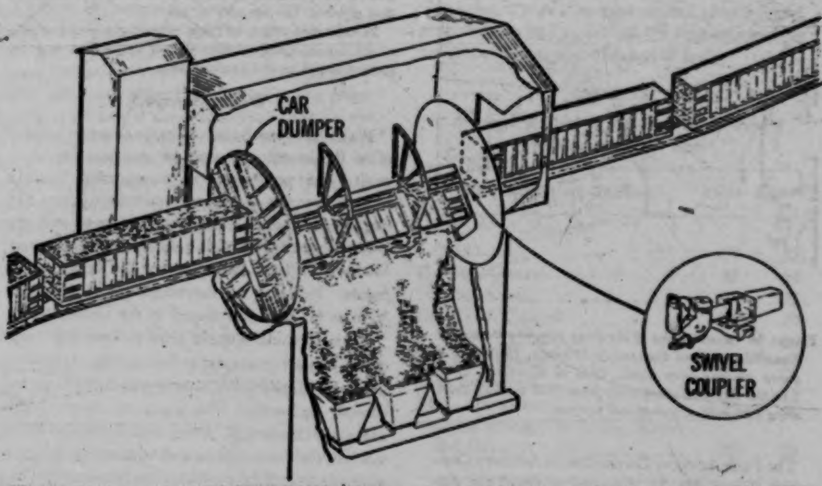


FIGURE 32 *Unit Train of the Commonwealth Edison Company is typical of newly developed specialized trains which can move coal from the mine to large power stations at greatly reduced costs because of simplified operations and shortened round-trip elapsed time. Each of these trains can carry in the order of 12,000 tons of coal.*

mittee, compares 1963 rates with the Committee's 1980 projection, and shows the large reductions in rail rates already in effect on volume movements of coal and the even greater reductions expected by 1980. With a high degree of automation even lower costs may be possible during the Survey period.

Pipeline Transport

The technology of pipeline transport for oil and natural gas is well developed and highly efficient. Some improvement in economy is possible in the future with the use of pipe of larger diameter and of greater strength to permit higher pumping pressures.

A new development which has excited much interest is the movement of coal in slurry form by pipeline. The successful operation of a 108-mile-long coal-slurry pipeline in the 6-year period 1957–63 has demonstrated the economic and technical feasibility of this method of coal transport. (See fig. 34.)

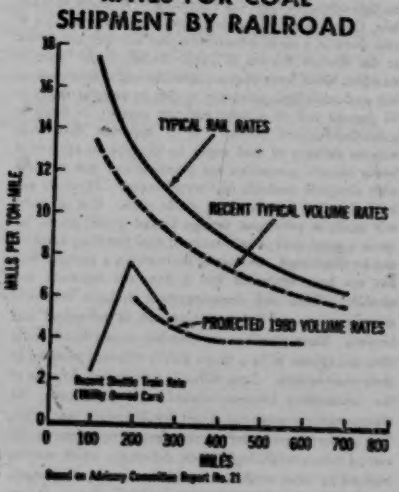


FIGURE 33

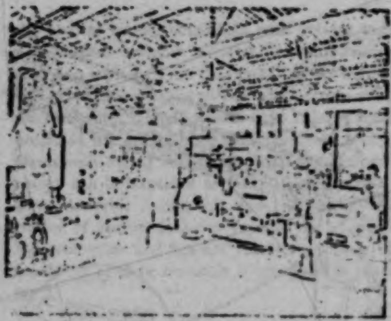


FIGURE 34 *View on one of the three pumping stations on Consolidated Coal Company's 108-mile, 10-inch, coal slurry pipeline from Cadiz, Ohio to Cleveland, Ohio. The line operated successfully from 1958 to 1963, delivering 1.25 million tons of coal per year.*

The Fuels Advisory Committee, in Advisory Committee Report No. 21, discussed in detail the considerations affecting a utility's choice of a coal pipeline *vis a vis* other modes of coal transport and summarized its findings as follows:

> After moving over 700 million ton miles of coal, cross-country shipment of fine coal has been amply demonstrated on Consolidation Coal Co.'s pipeline from Cadiz to Eastlake, Ohio. A successful demonstration of direct firing of coal slurry in a cyclone burner furnace has been conducted at the Werner Station in South Amboy, N.J. Tests at Eastlake, Ohio, have demonstrated the use of filter-pulverizer and centrifuge pulverizer system to dewater slurry to 22 percent and 18 percent moisture content for firing in pulverizer-furnace burner. It is apparent that large volume delivery of coal slurry by pipeline to centers of heavy electric generation are practical and can compete with alternate methods of transportation. Pipelines can be designed to handle lower grade coals. Use of slurry will result in additional savings at new power plants because a great deal of conventional coal handling facilities can be eliminated. Storage of inventory is a problem that has not been optimized but it does not represent any obstacle. Tests and demonstrations indicate that coal slurry can be used for cyclone as well as pulverized coal burners. Since pipelines are installed underground, there does not appear to be a major public relations problem in their construction. Once a line is constructed, because of the relationship between variable and fixed costs, the transportation component of cost should remain very stable. This protects against inflationary factors but deprives the user of future technological cost reductions which may be realized by other methods of coal transport. At present, there are legal problems in obtaining right-of-way. Every effort should be made to eliminate these legal problems so that pipelines can compete on merit.
>
> In the construction of large electric generating plants of the future, transportation of coal by pipeline must be given full and careful consideration.

Water Transport

Water transport by inland barge or ocean vessel is often the lowest cost mode of transport for oil or coal. The possibilities of transporting liquified natural gas (at a temperature below minus 116 degrees Fahrenheit) are being explored and the technical feasibility of this form of transportation has already been demonstrated for ocean movements. However no movements of liquified gas have so far been introduced in the United States.

Costs of transhipment tend to limit the availability of water transport to fuel sources near waterways and to generating stations which can be served directly by water. The waterway developments along the Mississippi, Ohio, and Tennessee River systems, the Great Lakes, and at coastal points provide many locations which can be served by the water carriers. (See fig. 35.)

A key element affecting the costs of water transport is the limitations which the physical characteristics of our waterways impose upon the barge or vessel. For example, the sizes of individual barges

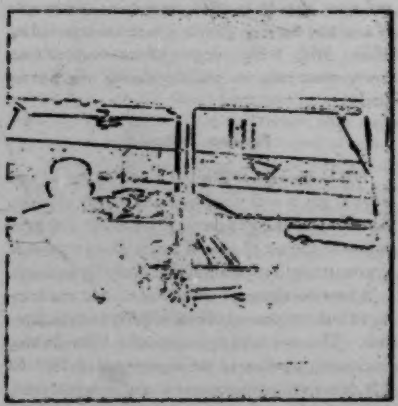


FIGURE 35 *Slack water barge navigation on the Nation's network of developed waterways economically moves large tonnages of coal to dock-side power plants.*

and groups of barges or "tows" (propelled by a single tow-boat) are controlled by the size of the locks and depth of the navigable channels. The outlook for lower rates on shipments by barge on the inland waterways is therefore limited by the physical characteristics of the waterways which do not lend themselves to ready expansion of tow sizes and quick turn-around equipment. However, increased tonnage on our waterways, larger locks, and stiffer competition from the railroads are factors which suggest that lower rates may be in the offing. Reductions in coastal coal and oil transport rates through use of special barges and tugs are also possible.

Transmission of Electric Energy

An alternative to the transport of fuels from their sources to electric generating stations is the transmission of electric energy at high voltage from generating stations located near the fuel sources. It will suffice here merely to point out this alternative. The technical and economic considerations affecting this choice are discussed in chapters 9 and 10. Indications of the manner in which this alternative is likely to develop during the next two decades are given in chapter 15.

Comparison of Delivered Energy Costs

Table 23 presents, region-by-region as well as for the Nation as a whole, the average cost of fossil fuels delivered to electric generating plants in 1962 and an estimate for 1980. The estimates for 1980 reflect the influence of such factors as an increasing proportion of mine-mouth as opposed to load center generation as well as anticipated improvements in the cost of mining and transport of fuels.

TABLE 23

Average Delivered Cost of Fossil Fuel
Cents per Million Btu

FPC Statistical Regions	1962 [1]	1980 [2]
I. Northeast	31	25
II. East Central	25	18
III. Southeast	24	21
IV. North Central	26	20
V. South Central	20	20
VI. West Central	26	18
VII. Northwest	23	23
VIII. Southwest	34	30
National average (excluding Alaska and Hawaii)	26	21

[1] Based on FPC and EEI data.
[2] FPC Estimate.

Conclusions

It is impossible to predict the combined effect of the considerations discussed in this chapter with respect to each fuel and each mode of fuel transport, including the alternative of electric power transmission. Nevertheless, as table 23 indicates, it would appear that we can expect a downward trend in the delivered cost of fuel in most locations.

CHICAGO SUN - TIMES

October 19, 1967

Pages 1. 4

DEFENDANT'S EXHIBIT 151

Chicago's Dirty Air —A Growing Peril

Because air pollution is a growing threat to the health of every Chicago area resident, The Sun-Times assigned medical writer Dick Kirschten to conduct an intensive investigation into the problem.

While looking into the causes—and possible cures—of Chicago's filthy air, he interviewed scores of government officials, medical and scientific experts, and just plain angry citizens.

The first of his reports is presented today.

By Dick Kirschten

Those teary-eyed residents of smog-shrouded Los Angeles are breathing cleaner air than we are here in Chicago, according to the U.S. Public Health Service.

*U.S. Public Health Service

In fact, the PHS report issued last summer rates the Chicago area's air pollution problem as the most severe in the country, with the exception of New York City where the air has been described as the filthiest in the world.

At that, Chicago is ranked even worse than New York and other cities when it comes to spewing poisonous and corrosive sulphur dioxide gas into the air.

And sulphur dioxide, as defined in the Medical World News, a leading professional magazine, is "(a) pollutant (which can) cause chest constriction, headache, vomiting, and death from respiratory ailments."

The reason that Chicago's air is full of sulphurous gases is no mystery.

According to the PHS estimates, more than 15,000,000 tons of potential soot and sulphur are shipped across the prairie each year in the form of soft coal from the mine-fields of southern Illinois.

U.S. Bureau of Mines statistics show that nearly two-thirds of Illinois' coal production falls into the category of "high sulphur content." The remainder falls into the "medium sulphur" range.

None of the coal mined in the relatively nearby southern Illinois and western Kentucky fields qualifies as low sulphur fuel—that is, having a sulphur content of one per cent or less.

As this soft coal is burned in the six-county Chicago metropolitan area each year, 1,671,000 tons of sulphur dioxide gas are belched into the atmosphere, the PHS says.

City of Chicago figures show that 9,000,000 tons of coal —nearly all of it the southern Illinois variety—are burned within the city annually, producing more than 300,000 tons of sulphur dioxide pollution.

Commonwealth Edison's generating plants burn two-thirds of this soft coal, the city figures show. The city's next largest category of coal consumption is residential heating, which accounts for about 1,500,000 tons annually. Industrial and commercial sources combine to burn another 1,500,000 tons.

Methods for removing sulphur dioxide from smoke and stack gases are still considered experimental and are not in common use. None of the coal burned in Chicago is subjected to any sulphur dioxide controls.

Chicago's air pollution ordinance places no restrictions on either the sulphur content of fuel or the emission of sulphur dioxide gas.

Other cities, notably New York and St. Louis, recently have enacted restrictions in an effort to clear their air. Los Angeles has had rules controlling the emission of sulphur dioxide since 1948.

Sulphur dioxide is an invisible gas. Most Chicagoans are visually quite aware that the area also is plagued by more obvious forms of air pollution.

Ordinary specks of dirt in the air—the air pollution professionals call them "suspended particulates" — also contributed to the Chicago area's low ranking.

Among the 65 metropolitan areas compared in the PHS

report, Chicago tied for seventh place when it came to concentration of particles of dirt in the air.

Much of this "particulate" matter is "fly ash," which also stems from the burning of coal. Other prominent sources of the ash are steel-making and the incineration of the vast amounts of garbage discarded each day.

Auto Biggest Offender

In terms of total volume of urban air pollutants, the biggest offender by far is the auto.

Pollution from cars was the third element in the PHS survey. The metropolitan areas were compared on the basis of gasoline consumption.

In terms of total gasoline consumption, Chicago ranked third with a total of 1.9 billion gallons. On the average, it was calculated that 512,000 gallons of gasoline are burned every year for each square mile in the six-county area.

Chicago's over-all low standing seems a rather dismal progress report when you consider that the city's efforts to abate air pollution date back 90 years. In 1874 — just three years after the smoke from the Great Fire had cleared—a citizens' association was formed to seek smoke control legislation.

In 1881, Chicago passed the nation's first civic air pollution ordinance, complete with a penalty clause.

Today, Chicago, has a highly regarded air pollution control program, replete with such modern electronic refinements as automatic air samplers, computer systems and a "spy in the sky" remote-control television camera.

THE MAJOR INGREDIENTS:

More than 15 million tons of coal are burned in the six-county Chicago metropolitan area each year, releasing 1,071,000 tons of sulphur dioxide gas in the atmosphere.

Chicago area vehicles burn 1.9 billion gallons of gasoline each year. Exhaust air pollutants come from some 512,000 gallons of gas used for each square mile.

Children on their way to school pass steel mill chimneys at 87th and Burley that pour out black smoke to add to Chicago's air pollution menace. Factories throughout city contribute to dirty air build-up. (Sun-Times Photo)

William J. Stanley, director of the city's program, describes the PHS ranking as "a grossly inadequate comparison." He also is quick to point out that the report refers not just to Chicago, but to the six Illinois counties of Cook, Du Page, Kane, Lake, McHenry and Will.

Two neighboring Indiana counties, Lake and Porter, which often have been implicated as contributing to Chicago's air pollution problem, were ranked separately. These counties, containing the steel mills of the Gary area were rated as having the nation's 11th most severe air pollution.

The authors of the PHS report concede their rankings are a rather "rough measure of the true severity of overall pollution problems."

Some pollution levels used in the calculations were projected for an entire metropolitan area on the basis of measurements taken at a single spot. Other levels are based solely on fuel consumption data rather than on actual measurements of pollutants in the air.

Weather Variations A Factor

A factor was included in the ratings to allow for weather variations from area to area which can profoundly affect the severity of the local air pollution situation. Los Angeles, for example, was penalized because of its unique propensity for long periods of air stagnation.

Despite all the qualifying factors, the rankings were issued with a statement expressing the conviction that "the list of cities arrived at gives a good over-all indication of the relative severity of their air pollution problems."

In other words, the U.S. Public Health Service is convinced that there is plenty of trouble in the air in Chicago—much of it in the invisible form of sulphur dioxide gas.

FRIDAY: Air pollution, respiratory disease and lung cancer.

DEFENDANT'S EXHIBIT 152

CHICAGO SUN TIMES

Page 44

June 26, 1969

ANTIPOLLUTION, ANTITRUST BILLS ARE SIGNED BY GOV. OGILVIE

Sun-Times Bureau

SPRINGFIELD, Ill.—Gov. Ogilvie Wednesday signed into law bills giving Atty. Gen. William J. Scott new powers to move against water and air polluters and a strengthened hand in antitrust actions.

Under the antipollution measures, the state receives the power to seek court action closing down polluters throughout the state.

In addition, fines for polluters are increased from $500 to $5,000, and jail terms hiked from 30 days to six months.

"Signing of these bills gives Illinois the toughest antipollution enforcement laws in the United States," Scott said in a statement.

One bill gives Scott power to enforce antipollution standards in Cook County. Previously, the Chicago Sanitary District and the city and county air pollution boards had exclusive enforcement jurisdiction.

Scott noted the antitrust legislation requires all state agencies to report two or more identical bids for investigation of possible collusive bidding.

In addition, he said, the new law gives him wide powers to move against price fixing and criminal infiltration of legitimate business.

DEFENDANT'S EXHIBIT

153

CHICAGO SUN TIMES
Page 37
July 14, 1969

Crackdown on air pollution!

Atty. Gen. William J. Scott has said he'll use strong new state powers to curb air pollution when cities fall down on the job. Good for him.

The air in Chicago, and other Illinois cities, too, is full of filth and there is precious little being done to purify it or even to make it moderately fit to breathe.

Chicago in particular has shown a reluctance to proceed against polluters despite an anti-pollution code adopted last year.

Last month, the City Council granted a year's delay in enforcement of limits on sulphur dioxide emission — which results from burning coal with a high sulphur content. Last week, the air pollution control appeal board found four steel firms to be behind schedule in agreed-to reduction of air pollutants. The firms were told merely to send in more frequent reports and to file them individually, rather than as a group.

There is no longer any excuse for softness toward those who befoul the atmosphere. Air is the stuff people breathe to live. When it is filled with noxious substances these are the things that enter people's lungs.

The Legislature gave the attorney general strong powers. They include injunctive power to close down plants that do not comply with state anti-pollution standards, and they include the power of criminal prosecution.

We welcome Scott's pledge that he will employ these tools, and hope his 25-man anti-pollution task force has good hunting. Anything that will bring polluters into line should be done — however harsh.

DEFENDANT'S EXHIBIT 154

CHICAGO SUN TIMES

Page 3

November 11, 1969

EDISON CUTS USE OF COAL, REDUCES AIR POLLUTION

By John Adam Moreau

The Commonwealth Edison Co., major contributor to air pollution in the Chicago area, reported it markedly reduced its burning of coal Monday.

A sharp drop in pollution was noted between early morning and midafternoon.

The company took the action on the fifth straight day of heavy smog.

As it did, the Businessmen for the Public Interest wiled a petition with the Illinois Commerce Commission saying Edison is guilty of "environmental violence" and should not be allowed the 6.1 per cent rate increases it seeks.

The commission is scheduled to begin a series of cross-examination hearings on the rate request, the first set for Wednesday.

The reduced burning of coal by Edison was important because the firm, according the city Department of Air Pollution Control, usually burns enough coal to create two-thirds of the sulphur dioxide pollution in Chicago.

Over-all, said William J. Stanley, the city's Air Pollution Control director, the generating of power causes one-fifth of the city's air pollution and Edison most of that one-fifth.

(The other over-all causes, each about one-fifth, are motor vehicles, refuse burning, space heating and other industry, said Stanley.)

Robert Lundberg, Edison's general staff engineer, said the company's action Monday means this:

Only 10 per cent of power for Chicago was being generated in Chicago; and 5 per cent of that power was created by coal burning, 5 per cent by natural gas. Ninety per cent of the power requirements came from generating plants outside Chicago, including facilities in Stickney, Downstate and in Wisconsin and Iowa.

These facilities burn coal, he said.

Lundberg said that he would confer with city officials Tuesday morning about restoring normal operations, providing the air has cleared sufficiently.

Meanwhile the Weather Bureau predicted that the conditions which have aided the air stagnation are beginning to change.

Weathermen said the high pressure system, which has been hanging over the area since Thursday, began inching eastward and fresher air began drifting in from the South.

Even the pollution statistics began to change. An early morning sulphur dioxide level of .25 of a part per million parts of air—2½ times above the danger level—eased down to .08 of a part by midafternoon.

Lundberg said Edison's action was taken on request of the city. He also said power was generated outside Chicago from Thursday afternoon through Friday morning, when coal burning was reduced.

Because power demands were less, the usual coal burning process was used Saturday and Sunday, Lundberg said.

The petition to the commerce commission, filed by attorney Joseph Karaganis, defined "environmental violence" as "the gross degradation of a natural environment with resultant damage to the medical and esthetic health of the community."

The businessmen's group is composed of a number of wealthy Chicagoans. Among its founders seven months ago was Gordon Sherman, president of Midas-International Corp.

Their petition stated, "Commonwealth Edison Co. could substantially reduce the amount of emissions of both sulphur dioxide and particulate matter. Low-sulphur coal is available in quantity. Devices are available which are

much more effective than those now used by Edison to trap particulate matter."

Asked why Edison cannot always use natural gas, Lundberg replied that not enough natural gas is available for Edison's needs. Asked whether, if Edison made it a policy to use natural gas, suppliers could accommodate their operations and stock enough, he said he doubted it.

He added that so far as he knew Edison never has tired to figure out whether it would be possible to switch to natural gas. The company expects to produce about 40 per cent of its power by means of atomic energy by 1973, he noted.

A spokesman for the Peoples Gas, Light & Coke Co. said there would be "complexities" in supplying a great increase in gas to Edison, mainly in accumulating large reserves supplies and in constructing the necessary tanks and pipelines.

Ward C. McCallister, president of Peoples Gas, told The Sun-Times his firm had tripled its sales of gas to Edison in the last year.

Stanley, the Air Pollution Control director, said Edison's equipment meets the demands of the city's pollution ordinance.

Asked whether he agrees with Illinois Atty. Gen. William J. Scott, who said air pollution has reached a "crisis," Stanley replied:

"That depends on how you define it. There are all kinds of air pollution problems and you have to devise special programs for each kind. Whether it's dangerous to you is up to a medic to say, not me."

DEFENDANT'S EXHIBIT 155

CHICAGO SUN TIMES
Page 2

November 13, 1969

8 UTILITIES FACE POLLUTION PROBE

By Donald M. Schwartz and Burnell Heinecke

The Illinois Commerce Commission on Wednesday ordered eight utilities to appear on Dec. 15 at an investigation into alleviating air pollution.

The firms ordered to appear are Commonwealth Edison Co.; Peoples Gas, Light & Coke Co.; Northern Illinois Gas Co.; Iowa-Illinois Gas and Electric Co.; Central Illinois Light Co.; Central Illinois Public Service Co.; Illinois Power Co., and Union Electric Co.

David H. Armstrong, commission chairman, acted on prodding from Gov. Ogilvie in the wake of six days of heavy air pollution in the Chicago area. Armstrong said in a press release:

"It is not the purpose of this proceeding to duplicate the enforcement of other agencies but rather to ensure that Illinois utilities are making the best possible use of available technology to produce needed energy at the minimal adverse effect on our environment."

Ducks Chicago question

Armstrong repeatedly turned aside questions at a press conference about the control of air pollution by the City of Chicago, saying the commission regulates utilities only.

But he did say that the commission has considerable power to require coal burning utilities, to install pollution control devices.

"We have broad powers," said Armstrong, "but as a practical matter I couldn't issue an order to shut Commonwealth Edison down and let the city go black."

Armstrong said further that his order tells People's Gas and Northern Illinois Gas Co. to give information at the hearing on the availability of natural gas.

The press conference was held in the State of Illinois Building, 160 N. LaSalle.

Earlier, Ogilvie had commented on air pollution in Chicago.

"It is clear from this episode that much too little was done too late," the governor said in Springfield as the persistent polluted haze was finally swept from Chicago skies by cool air from Canada.

The governor ordered Armstrong to obtain reports from major utility air polluters on their entire pollution abatement programs and on emergency plans for high pollution periods.

Ogilvie supported the order with the observation that the commission has legal power "to require every public utility to maintain and operate its plant in such manner as to safeguard . . . the public and . . . to require the performance of any other act which the health and safety . . . of the public may demand."

At the same time, the governor initiated a review which will include whether Chicago's exemption from state superivsion should be continued in the area of air pollution control.

3-area review

He directed Franklin D. Yoder, public health director, and Clarence Klassen, technical secretary of the Illinois Air Pollution Control Board, to examine three areas:

(1) State and city emergency anti-pollution plans and the means for making them more effective.

(2) The advisability of continuing to grant a state certificate of exemption to Chicago for control of air pollution.

Chicago has been permitted by the state to run its own show in air pollution control because it has its own pollution control department—just as the Sanitary District, until this year, was free of control by the state.

The district this year, however, was brought under the jurisdiction of the Illinois Sanitary Water Board.

(3) The City of Chicago's response to the just ended heavy air pollution.

In the meantime, lawyers in the State of Illinois Building, 160 N. LaSalle, wrangled over a Commonwealth

Edison Co. request for a 6.1 per cent rate increase while outside, pickets protested the utility's contribution to the air pollution burden.

At a brief hearing in the rate case, it was decided to postpone cross-examination of seven company witnesses, which was to have begun Wednesday, until Commonwealth Edison and opposing lawyers agree on cross-examination procedures.

DEFENDANT'S EXHIBIT 156

CHICAGO SUN TIMES
Page 8

November 18, 1969

CLEAN-AIR EDICTS OFFERED IN COUNCIL; DIMOUT SUGGESTED

By Harry Golden, Jr.

Two anti-administration aldermen proposed tough new measures to deal with air polluters, specifically the Commonwealth Edison Co., Monday in City Council.

Almost immediately Commonwealth Edison rejected the proposals, saying that the course of action it is taking to reduce air pollution is better.

The proposals came in the form of four resolutions, one by Ald. Jack I. Sperling (50th) and three by Ald. William S. Singer (44th).

Start to shout

All were referred to the Council's Health Committee. An administration-backed ordinance which would sharply increase fines for air pollution received support in the Council, but a vote was put off until the next Council meeting after a shouting match broke out on the floor.

Sperling's and Singer's resolutions were drafted separately, but all were aimed at combating conditions that led to the recent wave of air pollution in Chicago.

Sperling's resolution would direct the mayor, during times of air pollution alerts, to "call on industry, business and the general public to reduce their use of electricity to the lowest possible minimum" and to declare "power dimouts" until the pollution level was reduced.

Like war measure

Simultaneously, the mayor would urge suburban officials to join in the dimouts. Similar programs to cut

down on consumer use of power were instituted during World War II.

Singer's resolutions are aimed at changing the city's current air pollution control ordinance, which would force companies to use coal with 2.5 per cent sulphur content or less beginning next July 5. The law calls for a gradual reduction to a 1.5 per cent maximum by the end of 1974.

Sperling had said that "the primary source of sulphur dioxide in Chicago and suburbs is the 9,000,000 tons of coal of high sulphur content consumed by Chicago industry and particularly by the Commonwealth Edison Co., which burns 6,000,000 tons of high sulphur coal, two-thirds of the total amount."

Proposals outlined

Singer's proposals call for:

(1) Scrap the gradual reduction plan for high-sulphur content coal, and replace it with an amendment demanding use of coal with 1.5 per cent sulphur content or below by next July. The amendment would apply to all fuel users in Chicago, and within a mile outside the city.

(2) Abandon a provision which allows a company to continue burning high-sulphur coal in some plants if it reduces usage of the coal at other plants. This is aimed at Commonwealth Edison's plan to burn gas and use nuclear power at some plants. Singer said that "sulphur dioxide emissions must be reduced at every plant every day."

(3) Insist upon the latest anti-pollution precipitators at plants "to insure the removal of 90 percent or more of particulate matter." Singer said that Commonwealth Edison's precipitators now work at about 97 per cent efficiency, and that the company still emits some 17,000 tons of particulate matter annually.

Singer also called for public hearings to determine why Commonwealth Edison says not enough low-sulphur coal is available. He said that "billions of tons of coal in Virginia and West Virigina contain less than 1 per cent sulphur."

At a press conference called while the Council meeting was still in progress, two Commonwealth Edison officials rejected the Sperling and Singer proposals.

Nuclear program

Saying that the resolutions are not "squarely addressed to the city's problem," James O'Connor, assistant vice-president, and Wallace Behnke, vice-president, outlined the company's plans for reducing pollution.

O'Connor said the company is reducing the amount of coal burned in Chicago generating stations by retiring older generating units in Chicago, by burning increased amounts of natural gas, and by proceeding with a $900,000,000 nuclear power program.

He said the nuclear generating units will enable the company to ultimately reduce the coal burned in Chicago by more than 50 per cent.

O'Connor said that existing furnaces cannot burn low-sulphur coal, and the company could not burn the coal by next July.

"It would take several years to modify these plants for a fuel which is not available in the amounts required," he said.

To ask exemption

Behnke confirmed that Commonwealth Edison will ask the city for an exemption from reducing the sulphur content in its coal next July. He said the company would base the request on its plans to phase out the use of all coal.

O'Connor denied that the company is Chicago's major air polluter. He contended that "even with a complete shut-down of Edison's six Chicago area plants, 98 per cent of the air contamination would remain."

At the City Council meeting, a vote on the administration proposal to stiffen fines against air polluters was deferred until the next meeting when Aldermen Leon M. Despres (5th), Claude W. B. Holman (4th), Seymour Simon (40th) and Singer began to argue the merits of the city's current plans to combat pollution.

"The mayor of Chicago has the best program in the nation," Holman said, and Despres and Singer rose to argue. Aldermen Fred B. Roti (1st) and Vito Marzullo (25th) then moved to table the motion.

Mayor Daley, obviously displeased with the vocal antics in the presence of several groups of visiting school children, said "That was a great demonstration before these fine children."

DEFENDANT'S EXHIBIT 157

CHICAGO SUN TIMES

November 20, 1969

MIKVA BILL WOULD MAKE AIR POLLUTION A FEDERAL OFFENSE

Sun-Times Bureau

WASHINGTON — Rep. Abner J. Mikva (D-Ill.) Wednesday introduced in the House a bill that would make air pollution a federal offense and set federal standards on pollution sources.

The bill, titled the Air Pollution Abatement Act of 1970, was cosponsored by 19 other congressmen, including Rep. Frank Annunzio (D-Ill.). It was sent to the House Interstate and Foreign Commerce Committee.

The bill calls for additional rules and private remedies for air pollution abatement, and would give citizens the right to sue in state or federal courts.

Fines up to $2,000 a day

Penalties of up to $2,000 a day are provided for polluters, and the secretary of Health, Education and Welfare would be authorized to set special standards where climatic conditions make air pollution especially dangerous to health.

The provisions would take effect when an "inversion" developed, as it did in the Chicago area earlier this month. An inversion is the trapping of pollutants by layers of air of different temperatures.

In such situations, the secretary would have emergency powers to shut down for up to 72 hours industries that contribute to air pollution. The offender would be required to continue paying wages during the emergency.

Mikva said the bill would make enforcement of stringent national air pollution standards the policy and practice of the United States.

Chicago's air unsafe

"If our cities are to be saved, they have to have breathable air for the people who live there," he said. He noted that preliminary results of a government study indicated that a large percentage of Chicago's population is breathing air polluted over twice the "safe level" established by medical authorities.

"Citizens of this nation know that our environment will continue to deteriorate as long as Congress coddles the polluters of the very air we breathe," he added.

The bill also calls for an enforcement of state and local standards by the federal government or injured citizens when local authorities fail to act.

DEFENDANT'S EXHIBIT 158

CHICAGO DAILY NEWS
Page 3
December 1, 1969

Pollution fight

Edison tells coal doubts

By Jay McMullen

An official of Commonwealth Edison Co. said Monday he is pessimistic about the company's ability to burn large quantities of low-sulphur coal.

Nevertheless, said Byron Lee, assistant to the president, Edison will try to burn 800,000 tons of low-sulphur coal next year compared with the 30,000 tons it burned in the last five months.

The company burns 6,000,000 tons of coal a year, most of it high-sulphur. High-sulphur coal creates a higher quantity of dioxide, a major air pollutant.

THE CITY Council has ordered industry to reduce the sulphur content of its coal to 2.5 per cent by July 1, 1970, and 1.5 per cent by 1974. Edison, which mainly burns coal of about 3.5-per cent sulphur, has said it will not be able to meet the council's deadlines.

Lee said at a press conference that Edison's tests of low-sulphur coal, which ranged in sulphur content from 1 to 1.5 per cent, turned up these defects:

- The coal created twice as much air-polluting particulate matter as high-sulphur coal.
- It cost twice as much as high-sulphur coal to produce an equal amount of heat.
- Slag runoff caused a rock-hard residue that had to be chipped off a boiler with a jackhammer.
- It is difficult to get it mined and shipped to Chicago "on a regular and dependable basis."

LEE SAID Edison's low-sulphur coal came from Wyoming and Montana, and not from Virginia and West Virginia where billions of tons of low-sulphur coal are said to exist.

He said the Eastern coal causes high amounts of slag that clogs up boilers, cannot be ground in Edison's coal grinders and causes even more particulate matter than Western coal.

Lee added that it would cost Edison $15,000,000 to $20,000,000 to shift entirely to low-sulphur coal.

He said the company will use only 4,000,000 tons of high-sulphur coal next year and will drop to 2,000,000 to 2,500,000 tons by 1974.

THE WALL STREET JOURNAL,
Wednesday, January 7, 1970 19

'Black Diamond' Boom: Kleenburn Coal Mines Enjoy Demand Surge

* * *

Air-Pollution Worries Spark Orders for Low-Sulphur Fuel Mined in Big Horn Mountains

By a WALL STREET JOURNAL Staff Reporter

KLEENBURN, Wyo.—This tiny, north central Wyoming town, named for the clean-burning coal mined here, is suddenly enjoying a boom, thanks to growing public concern over air pollution.

Coal has been mined in this section of the historic Big Horn Mountains since the days when Buffalo Bill Cody operated the nearby Sheridan Inn. But until recently its low sulphur content didn't seem to attract much demand for Kleenburn's "black diamonds."

Now, however, large orders for the coal from such distant utilities as Chicago's Commonwealth Edison Co. and Kansas City Power & Light Co. have forced Big Horn Mining Co., into double work turns. Big Horn Mining is a subsidiary of Peter Kiewit Sons' Co., an Omaha-based construction concern.

Instead of being shipped a few carloads at a time, Kleenburn coal is being loaded into unit trains of 60 to 65 cars each, reports the Chicago, Burlington & Quincy Railroad, which serves the area. The Burlington says it has had six unit trains in operation since Dec. 10 and plans 34 more. The road currently runs three loaded trains each week to handle the mine's output.

To further enhance the sudden appeal of Kleenburn coal, the Burlington says it cut the shipping rates to Kansas City to $5.26 a ton from $6.60 and to Havana, Ill., to $8.43 a ton from $11.30. From Havana the coal is barged to Chicago.

DEFENDANT'S EXHIBIT 160

WALL STREET JOURNAL
Page 1
March 19, 1970

Business Bulletin

A Special Background Report On Trends in Industry and Finance

POLLUTION CRACKDOWNS convince companies to close some facilities.

They find it more economical than trying to equip marginal plants with costly antipollution controls required by many governmental units. Giant Portland Cement Co. phases out a 65-year-old plant at Egypt, Pa., rather than spend $1 million to comply with Pennsylvania's air pollution control law. Jones & Laughlin Steel Corp. will close parts of its Pittsburgh iron foundry for similar reasons. Ohio Edison Co. decides to phase out four, occasionally used, coal-fired generating units in Toronto, Ohio, when restrictions tighten, rather than install new controls.

The pace of closings is expected to increase as enforcement agencies step up activities. "We'll lose one-third of the 1,800 gray iron foundries" when air pollution codes are in effect across the country, says a spokesman for the Gray and Ductile Iron Founders Society in Cleveland.

The Texas Air Control Board claims it was influential in getting two lumber companies, a feed supplement plant and a lime plant to close last year.

* * *

DEFENDANT'S EXHIBIT 161

MID-WEST COAL PRODUCERS INSTITUTE, INC.
307 NORTH MICHIGAN AVENUE
CHICAGO, ILLINOIS 60601
AREA CODE 312 - TELEPHONE FINANCIAL 6-7447

OFFICE OF
THE PRESIDENT

THE NEWS THAT NOBODY PRINTS

Dear Sir:

The sulfur dioxide level in the Chicago area has declined steadily over the last six years. The attached chart illustrates this improvement. In 1968 and 1969 the level was well below the suggested goal of less than .040 parts per million as published in the U. S. Department of Health, Education and Welfare Criteria.

This improvement in the ambient air is due entirely to the voluntary efforts made by Chicago citizens, since the sulfur restrictions of the Chicago Air Quality ordinance do not become effective until July 5, 1970.

The 1969 average sulfur dioxide level of .026 parts per million was reached five years ahead of the schedule projected by the coal industry when the ordinance was being considered.

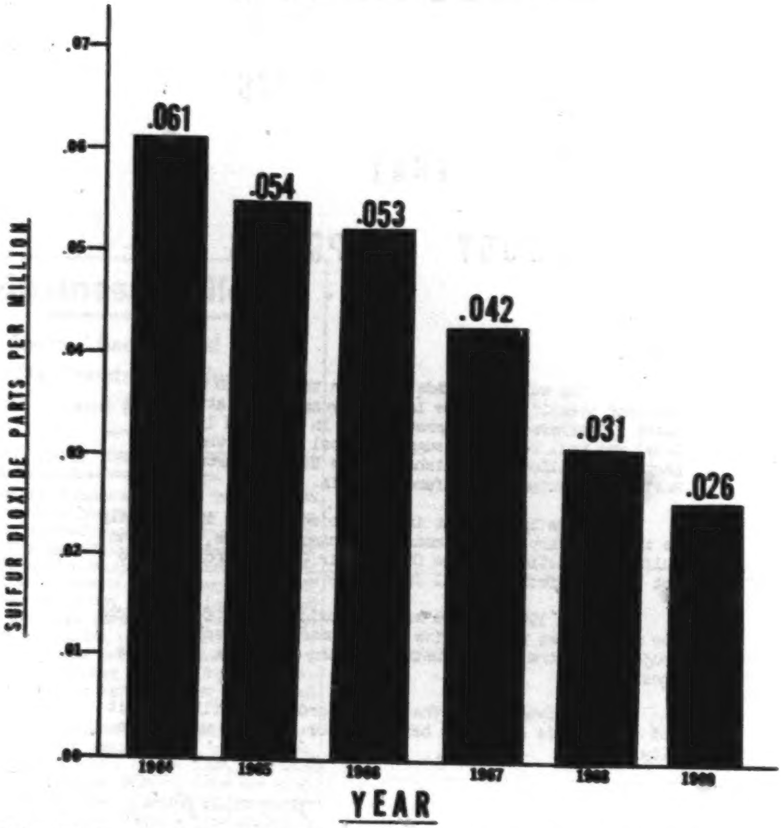
Enforcement of the Chicago ordinance will prohibit 86% of Illinois coal from being sold or consumed within the city.

Very truly yours,

Otis J. Gibson

Otis J. Gibson
President

CHICAGO AIR YEARLY AVERAGE SULFUR DIOXIDE



Source: Chicago Department of Environmental Control Statistics; Figures shown are the arithmetic average of the 24-hour averages for the 20 station network in the Chicago area.

Prepared By: Mid-West Coal Producers Institute, Inc.
February, 1970

14 THE WALL STREET JOURNAL, Thursday, March 5, 1970

New Ruckus on Foreign-Oil Imports to Pin Nixon Between Pollution Issue, Coal Groups

By Burt Schorr
Staff Reporter of The Wall Street Journal

WASHINGTON — Last month, President Nixon sidestepped a possible collision with the oil industry over a Cabinet task force proposal to replace existing oil-import quotas with a system of tariffs. He adroitly delayed final action, possibly until after Election Day.

A new foreign-oil ruckus is heading Mr. Nixon's way, this time involving the coal industry, and it's doubtful the President will be as lucky in finding a safe neutral corner.

The conflict—currently working its way toward the White House through the Oil Import Appeals Board deep in the Interior Department—grows out of a request by Commonwealth Edison Co. to import foreign residual oil to fuel its Ridgeland generating station just outside Chicago's city limits. When Mr. Nixon approaches this question, however, he'll find his Administration uncomfortably pinned between two larger and politically more troublesome issues.

Air Pollution Rhetoric

On one side is the credibility of Nixon Administration rhetoric about wanting to clean up the environment. Commonwealth, to meet a 1970 commitment to help improve the quality of the air Chicagoans breathe, wants to substitute low-sulphur-content imported oil for the high-sulphur-content domestic coal currently being burned at Ridgeland. Thus a rejection of the utility's import application could be interpreted as meaning the Nixon Administration really doesn't care much about clean air. Deferring final action—as was done on the task force proposal—could lead to much the same interpretation and hurt Republicans in the fall election.

On the other side are the coal industry and the fact that existing oil-import regulations dating back to 1959 have permitted only a relative trickle of foreign residual oil (the molasses-like end-product of some refinery processes) into the important 15-state midcontinent region known as District II, which includes Chicago.

Coal representatives argue that once this barrier is breached, many other District II coal burners with air-pollution problems will flock to Washington to obtain foreign oil rights for their plants—the substantially higher cost of oil notwithstanding. This would mean a serious setback for coal demand in the 15 states, which currently account for more than half of total yearly U.S. coal use. As a result, the coal argument runs, promising techniques for removing most of the sulphur from stack emissions of coal-fired plants will languish for lack of interest, and investors will be leery of risking their money in development of new coal mines.

Coal-Industry Opposition

A number of Capitol Hill heavyweights from coal states, whose views can't easily be ignored by the White House, already have been mobilized behind these arguments by the National Coal Policy Conference and the National Coal Association, two major industry lobby groups. Together with the United Mine Workers union, they represent the chief formal opposition to the Commonwealth Edison application.

Rep. Edmondson (D., Okla), chairman of the House Mines and Mining subcommittee, for example, wrote the Oil Import Appeals Board that "the precedent-shattering nature of Commonwealth's application, if approved, will have seriously harmful effects upon our country's economic posture and national security. Apparently, Commonwealth has not concerned itself with the far-reaching effects approval of their application would have on similarly situated industries. . . . It is difficult for me to see how the many, many additional applications which would inevitably follow could be treated differently."

For the oil import board, at least, such appeals don't seem to have had much effect. The panel's chairman, Lewis Flagg III, an Interior Department employe, hasn't released the Commonwealth ruling. The board's other two members, Stanley Nehmer, Deputy Assistant Commerce Secretary for Resources, and Paul H. Riley, Deputy Assistant Defense Secretary for Supply, who constitute the necessary majority, have signed a finding that the utility is faced with "exceptional hardship" and should get 4.5 million barrels of imported residual oil in the 12 months starting April 1.

Opinion Dismisses Objections

The majority opinion dismisses coal-industry objections and seems to open the door wide to other foreign-oil applicants. The opinion states that the "basic issue . . . is not one of coal versus oil since the petitioner has made a decision to discontinue burning coal as a basic fuel at the Ridgeland station under any circumstances." The opinion notes that Commonwealth did get a belated offer of domestic residual oil from Standard Oil Co. (Indiana), but this fuel would contain 70% more sulphur than the foreign oil and cost a third more.

A formal appeals board decision, however, will represent only a first step through the oil import labyrinth for Commonwealth. Next, it's up to Interior Secretary Hickel to lift the ceiling on residual oil imports into District II, currently set at a mere 219,000 barrels yearly. Presumably such action first would have to clear the President's new interagency committee on oil import policy and perhaps the White House itself. Routine issuance of an import license by the Oil Import Administration would follow.

New Ruckus on Foreign-Oil Imports to Pine Nixon Between Pollution Issue, Coal Groups (Continued)

Interior Department officials doubt, though, that this emergency relief procedure, provided under the original Eisenhower oil-import proclamation, is the proper way to handle the backlog of additional residual-oil applications building up rapidly in the appeals board office. So far, District II import license requests totaling more than 25 million barrels (equivalent to about six million tons of coal) are on file.

Extent of Demand Unclear

Just the other day, for example, Detroit Edison Co. asked for 3.5 million barrels in the 12 months beginning April 1 to provide back-up fuel for its Delray station. The plant normally burns pollution-free natural gas, but increasingly tight supplies of that energy source have increased the periods when its gas is diverted to home use. More critical, the utility says, is the fact that domestic refiners from which it formerly purchased residual oil aren't any longer offering to supply it.

There are strong indications, moreover, that the full extent of demand for foreign residual oil in the 16-state region has only begun to reveal itself. One District II case presently before the Oil Import Appeals Board involves a group of 12 oil-terminal operating companies, which hasn't specified how much residual oil its members would like to bring in. Elmer L. Hoehn, a member of the law firm representing the terminal operators (and formerly oil import administrator in the Johnson Administration) says his clients are still canvassing their customers' needs. Preliminary findings suggest that dozens of new local air ordinances will require "tens of millions" of barrels of foreign residual oil to satisfy them, Mr. Hoehn comments.

For the long term, it's obvious that the Administration must at least consider a broad policy change designed to make heavy industrial fuel oil as easy to obtain in District II and other districts as it is currently in the 16 eastern seaboard states comprising District I.

Oil Imports in Other Areas

In prior years, when the environment wasn't a major issue, residual oil use hinged largely on its transportation costs. Because it had easy tanker access to Venezuelan refineries, therefore, District I started out under the import program with an "historic" right to import vastly more fuel oil than all the other districts combined. In 1966, controls on foreign residual oil into District I were loosened to the point that, in effect, importers could bring in all they were able to sell.

The recent report of the Cabinet task force on oil-import control indicates broad support already exists within the Administration for opening the entire country to foreign fuel oil. The panel majority, representing five of its seven members, questioned the rationale of allowing imported heavy oil access to one region but not others. It said this inequity would be ended in the overall change to a tariff system. The minority members, Commerce Secretary Stans and Interior Secretary Hickel, also suggested that "consideration should be given to applying (District I) policy uniformly across the U.S.," even though the two dissenters would retain other features of the present quota system.

Most Venezuelan and U.S. crude oils actually leave the ground with sulphur levels close to those in coal, and the troublesome mineral eventually ends up in the residual product. However, there are well-established commercial processes for desulphurizing oil—an advantage coal still lacks. A number of companies currently are working on ways to remove sulphur dioxide, the gas produced when high-sulphur-content coal is burned, but many experts in the field believe it will be at least several years before all of the wrinkles are out of these techniques.

Meantime, frustrated coal executives have watched residual oil use mushroom in District I at the expense of their product. "In the 1966-67 period, after controls were dropped, 27 utilities from New England to Washington decreased their use of coal by 10% while increasing their consumption of oil by 85%," the National Coal Association told the Oil Import Appeals Board. "Almost without exception," the association said, oil also has been the fuel chosen for new East Coast fossil fuel plants. As a result, it said, coal "barely held its own" in District I between 1966 and 1969; in the first nine months of last year, its use actually declined, while oil use continued to grow.

DEFENDANT'S EXHIBIT 163

THE WALL STREET JOURNAL, Thursday, March 26, 1970 5

Commonwealth Edison Is Allowed to Import Low-Sulphur Fuel Oil

Hickel Says One-Year License Doesn't Establish New Policy; Coal Industry Fought Action

By a WALL STREET JOURNAL Staff Reporter

WASHINGTON — Interior Secretary Hickel granted Commonwealth Edison Co. the right to import 4.5 million gallons of low-sulphur residual fuel oil for its Ridgeland power station near Chicago.

The import license, effective for the year beginning April 1, had been opposed vigorously by the coal industry, chiefly on the grounds that foreign residual oil previously hasn't been licensed for use in Midwestern or Southern states and that its admission at this time would sharply cut coal sales. The conflict had placed the Nixon Administration in a squeeze between influential coal-state lawmakers on Capitol Hill and a desire to maintain its clean-environment reputation.

Demand for low-sulphur foreign residual oil is building in many localities because of new air pollution control ordinances. Because of technological changes, U.S. refiners currently have little residual oil to sell. Coal is a substantially cheaper fuel, but commercially acceptable methods for removing sulphur from coal fire stack emissions still are only under development.

Secretary Hickel said he is granting Commonwealth Edison's request "in the interest of curbing air pollution in the Chicago region." He emphasized, though, that his decision is based "on a very special set of circumstances and does not represent establishment of a new general import policy for low-sulphur residual fuel oil." A test of such policy is likely to occur in the near future as the Interior Department handles a number of requests similar to Commonwealth's.

THE REAL MEANING OF ALASKAN OIL FINDS

Benefits for all the U.S. are to flow from Arctic oil fields in the 49th State.

Potential output would double the nation's proved reserves. Enough oil to meet all demands is assured even if U.S. were cut off from other sources.

Huge pipeline is to carry oil down through Alaska for shipment to the West Coast, bringing initial benefits to that region.

Reported from
NEW YORK AND WASHINGTON

The full meaning of recent oil strikes in northern Alaska is suddenly becoming clear to industry experts and Government officials.

The essential fact is that Alaskan finds will make the U.S. self-sufficient in reasonably priced oil for the foreseeable future.

Almost overnight the U.S. appears to have doubled its petroleum reserves.

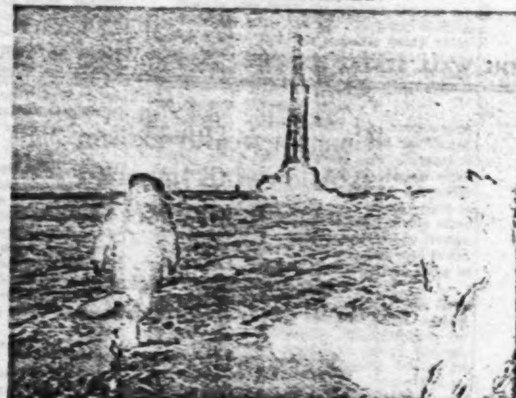
Vast new pool. The center of world oil exploration will now move to the Arctic—U.S., Canadian and Russian—says Walter J. Levy, a top international oil consultant.

Source of all this interest is a pair of wells on land near the Arctic Ocean's Prudhoe Bay. Atlantic Richfield Company and a subsidiary of Standard Oil Company (New Jersey) drilled them last year. Result: DeGolyer & MacNaughton, a Dallas oil-consulting firm that announced the strikes, estimated a pool holding 5 to 10 billion barrels of oil had been hit.

Oil companies have been racing for drilling rights on what's called Alaska's North Slope ever since. But only now are the experts putting together a clear picture of what the Prudhoe Bay discoveries mean. And that picture is bright.

Alaska may be the biggest and most important oil discovery since Middle Eastern fields were found.

Outlook: *Independence.* Before Prudhoe Bay, the U.S. faced the prospect of having to import 50 per cent of its oil needs by 1980. Either that, or the price of oil would have had to be artificially pegged here at around $4.50 a barrel, compared with about $3 today, in order to boost production from high-cost wells, oil shale and coal.



—Photo: Atlantic Richfield Company

It takes hardy men to tend the drilling rigs in Alaska. The recent discovery of a vast new field near the Arctic Ocean may have doubled U.S. petroleum reserves.

Now, however, the U.S. will be able to hold prices at present levels, or possibly even let them drop somewhat. The Government currently keeps oil prices at home about double the price of oil in the world market by restricting imports. Imports are set at 12.2 per cent of demand.

Americans, with Alaskan oil coming in, will not have to rely on production in Arab-ruled lands of the Mideast, in Venezuela or even in Canada for gasoline, heating oil and other products made from petroleum.

Counting the riches. How much oil is there in Alaska? No one knows the answer yet. The estimate of 5 to 10 billion barrels for the Prudhoe Bay field is for just one geological "structure." And there are an estimated 10 to 20 similar structures in the North Slope region alone.

Even oil men with reputations for conservative estimates are projecting 40 billion barrels for the North Slope if present soundings continue to prove out. You see how much oil that is by comparing it with total reserves for the rest of the U.S.—only 32.5 billion barrels, according to "The Oil and Gas Journal," trade magazine for the industry.

And that isn't all. Alaska also has nine other geological areas like the North Slope—"sedimentary basins"—where oil might be found. It is no wonder that Mr. Levy says every large U.S. oil firm will have an "absolutely compulsive need" to hunt for oil in the Arctic once the large size of the resources is established.

For domestic use. Where will all this oil be sold? Only in the U.S., say the experts. Europe, Japan, other oil-hungry regions will not get any.

Reason for this is simple economics. Oil sold in the U.S. brings $3 a barrel, compared with about $1.50 abroad. The only thing that would change this pattern would be discovery that the Alaskan oil is so cheap to produce it could compete against Mideastern crude oil. And that isn't considered likely.

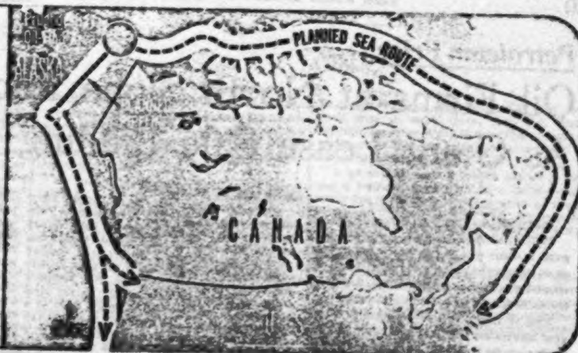
Pipeline-construction plans just unveiled by three companies with the big-

TAPPING ALASKA'S OIL WEALTH —

Vast oil discoveries at Prudhoe Bay, on Alaska's North Slope, can help keep the U. S. self-sufficient in oil — if transportation can be arranged at reasonable cost. Map shows two plans now in the works:

1. A pipeline across Alaska to the Cook Inlet area, where ships would pick up oil for West Coast ports.

2. An all-tanker route from Prudhoe Bay to the East Coast of U. S. via a Northwest Passage through islands north of Canada's mainland.



gest stakes in Prudhoe Bay—Atlantic Richfield, Jersey Standard and British Petroleum Company—show what is to happen.

Prudhoe Bay oil is to be piped to Alaska's southern coast, shipped to Puget Sound and other Pacific Coast points for processing and sale there. Atlantic Richfield already is planning to build a 100,000-barrel-a-day refinery near Bellingham, Wash., to process Alaskan oil. Other refineries may be built in Alaska.

The pipeline is to be one of the world's biggest—48 inches in diameter and 800 miles long. Initial capacity is to be 500,000 barrels a day, just about the amount of oil the West Coast is thought to need for self-sufficiency.

Ultimate capacity for the trans-Alaskan line is said to be 1.5 million-plus barrels a day. This indicates to oil-industry men that within a relatively few years a new pipeline probably will be built connecting the Seattle area with Midwestern industrial centers as far east as Chicago.

Trouble for Canada. Left out, as U. S. analysts now see the future, is Canada's oil industry—unless Canadian Arctic oil can be developed and transported cheaply enough to find a big market in Europe. The price problem makes this doubtful, in the opinion of some experts.

Canadians are currently exploring for oil in their own Arctic islands and near the mouth of the Mackenzie River, not far across the border from Alaska.

A number of other Canadian oil finds are shut in—nonproducing—because of lack of transportation or lack of markets.

Oil men in Canada have been pushing for a pipeline running from Prudhoe Bay diagonally across Canada to Chicago. Their proposal would have given U. S. companies free transit in return for letting Canadian producers use the line for sending their crude petroleum to market in the U. S.

Now it appears that such a pipeline is a long way off.

In fact, say the experts, even Canada's present exports to the U. S. may be in trouble. Canada currently sells about 500,000 barrels of oil a day to the U. S. at the American price of $3 a barrel and imports some 600,000 barrels a day at the world price of around $1.50 a barrel. Thus, it is argued, the U. S. consumer subsidizes Canadian companies.

Floods of Alaskan oil also are likely to increase demands from owners of high-cost wells in older producing States for lower oil imports from Canada and elsewhere. That promises headaches for President Nixon: How to keep oil men in the U. S. and governments in Canada and Venezuela happy.

Officials in Washington believe the outcome will be stepped-up consideration of a U. S.-Canadian continental oil policy. This presumably would mean free access for Canadian oil to lucrative U. S. markets. But it probably would also mean a requirement that Canada agree to limit imports of cheap foreign oil, it is reported in Washington.

Boost for shipbuilders. Analysts are discovering, too, that the benefits of Alaskan oil seem sure to spread well beyond the oil industry. To the shipbuilding industry, for one.

New tankers will have to be built to carry the large amounts of oil coming out of the Alaskan pipeline to refineries in the "lower 48" States. Federal law requires that all trade between U. S. ports be carried in American-made and manned ships.

No orders have been announced yet, but industry sources understand several 200,000-ton tankers are soon to be built, the largest ever made in the U. S. A possible step in that direction is a new project by Bethlehem Steel Company's Sparrows Point shipyard to construct facilities for 200,000-ton ships.

In San Francisco, Bethlehem also is building big new dry docks capable of holding a supertanker for repair.

Northwest Passage? Alaskan oil could finally accomplish what Henry Hudson and other explorers couldn't—the opening of the fabled Northwest Passage.

A Jersey Standard tanker, the *Manhattan*, is being fitted with a new type of ice-breaking prow for a try this spring at sailing from the Atlantic Coast, across the top of Canada to Prudhoe Bay.

The bow, named the "MIT bow" after the Massachusetts Institute of Technology where it was developed in co-operation with the U. S. Coast Guard, lifts the ship onto the ice, where sheer weight causes it to break through. This leaves a channel behind the lead ship for a train of smaller tankers to follow.

The Canadians are experimenting with still another type of icebreaker, the "Alexbow," named after inventor Scott Alexander. It splits the ice from below and throws it aside.

If the new icebreakers work, they would open the heavily populated Northeastern U. S. to supplies of Alaskan oil. But don't look for a completion of the Northwest Passage all the way into the Pacific Ocean soon, say the experts. Thickness of ice around the northwestern tip of Alaska runs 50 feet or more, far too much for today's icebreakers to tackle.

If ice does block the tankers, it will be one of the few hitches in Alaskan oil's remaking of the industrial and transportation map of North America.

DEFENDANT'S EXHIBIT 165

30 THE WALL STREET JOURNAL, Friday, May 2, 1969

Petroleum Prize

Oil Firms at North Slope Race for Data As Giant Lease Sale Bidding Approaches

By [illegible]
Staff Reporter of THE WALL STREET JOURNAL

PRUDHOE BAY, Alaska — A giant poker game is under way on this frozen Arctic desert as oil companies prepare for what many veteran oilmen are betting will be the first $1 billion lease sale in the industry's history.

They're racing in tightest secrecy to gain vital information they'll need to bid in mid-September on up to 700,000 acres of state leases on Alaska's North Slope and under the Arctic Ocean near what's likely to prove the biggest oil field in North America.

To probe for these data through 1,500-foot deep permafrost (a mixture of permanently frozen ice, mud and gravel), 14 oil companies have assembled 22 towering drilling rigs on the Slope, with at least three more on the way. To support their frantic drilling activity, they've already moved, mainly by air, more than 500 million pounds of equipment and supplies into this area, about 1,300 miles from the North Pole. And they've built an amazing complex of air fields, base camps, supply dumps and all-weather roads atop insulating five-foot-deep layers of gravel over about a 100-mile expanse of barren plain.

Those companies and unnumbered others who don't have rigs or acreage on the Slope have dozens of "oil scouts" sleuthing for clues as to what the others are finding. Some companies have posted armed guards at their drill sites, and at least two have cleared out all contractor personnel before making well tests. Reports are sent by courier, and radio references to wells are coded. Rig crews even try to shield their operations from scouts in planes and helicopters.

Watching at the Airport

With security so tight on the Slope, many scouts are posted 400 miles to the south in Fairbanks, where they watch supplies being loaded aboard long lines of cargo planes around-the-clock at the Fairbanks airport, and observe airline counters and hotels to see what personnel are heading for the Slope. If a company ships a certain size of "casing" (heavy steel pipe used to seal off liquids from a hole) or a "Christmas tree", (the assembly of valves and fittings used to control oil or gas flow from a well), or a certain well services specialist arrives in town, it can be a valuable clue to what's happening at a rival's drillsite.

"All exploratory wells on the Slope right now are simply being placed where they can best evaluate unleased acreage and provide as much information as possible for next fall's lease sale," Thornton F. Bradshaw, president of Atlantic Richfield Co., says in New York. "This means the tightest security, and we hope our security is as tight as anyone's," he adds.

It was a series of announcements last year by Atlantic Richfield that touched off the excitement here. They reported that an evaluation of data from two oil discovery wells on acreage held jointly by Atlantic Richfield and Humble Oil & Refining Co., chief domestic subsidiary of Standard Oil Co. (New Jersey) gives the "reasonable expectation" further drilling will prove up an oil field containing 5 billion to 10 billion barrels of crude oil.

Magnitude of Reserves

The latter figure would be more than one-fourth of known oil and gas liquids reserves in the rest of the U.S. and as much oil as Saudi Arabia has produced to date. It also would exceed the six-billion-barrel East Texas Field, currently North America's biggest, which nearly wrecked the industry with a flood of oil in the initial years after its discovery in 1930.

"Everything drilled by everybody on the Slope will be tight as a drum until September," says Harry Warman, Alaska operations manager for British Petroleum Co., the only other company to concede publicly it has made an oil discovery on the North Slope, and second only to Atlantic Richfield in total drilling activity here.

A green "Christmas tree" (this assembly of pipes and valves is the only kind of tree on the Slope) sits atop BP's Put River No. 1 well, but the company steadfastly declines to disclose any test data from the well, or to comment on reports it's testing another possible discovery at its Put River 22-11-13, five miles to the west.

Alan Calderwood, BP's 37-year-old drilling superintendent, who came to the frigid Arctic from steamy Abu Dhabi on the Persian Gulf, does concede, however, that "it's likely" Put River No. 1 found the same oil formation as did the Atlantic Richfield-Humble Prudhoe Bay No. 1, three miles to the north, and the Atlantic Richfield-Humble Sag River No. 1, three miles to the southeast.

Still more reticent are Standard Oil Co. of California and Mobil Oil Corp. (operator for a joint venture with Phillips Petroleum Co.). The word all over the Slope is that each of the two has completed an oil discovery well, but both companies decline to confirm or deny the reports. Perhaps significantly, BP is drilling a well just 1,320 feet north of California Standard's rumored discovery, about six miles south of Put River No. 1, and is preparing another rig site just 1,320 feet northeast of the same well. There's also a rumor that Atlantic Richfield-Humble have a third discovery well six miles east of their Sag River well.

Pan American Petroleum Corp., exploration

and production subsidiary of Standard Oil Co. (Indiana), also has reported discovery of natural gas about 40 miles southeast of Prudhoe Bay, but both Pan American and other companies have decline to evaluate the significance of that find.

OIL FIRMS AT NORTH SLOPE RACE FOR DATA AS GIANT LEASE SALE BIDDING APPROACHE
(Continued)

More Valuable Than Money

Under Alaska law, oil companies can keep well data secret for up to 25 months. They must file reports with the state within a month of a well's completion, but this information can be kept confidential for up to two years. As an extra precaution, the state has locked the North Slope reports in a bank vault in Anchorage. Jokes the Alaska operations engineer for one major oil company, "I wish my talents included opening bank vaults—they could keep the money; I'd just like a peek at those reports."

The Securities and Exchange Commission has also clamped a lid on announcements about reserves and probable production flow rates until more wells are drilled on the Slope. But high-level sources report the North Slope wells are "Middle East type" and are likely to produce at rates "of about 5,000 barrels a day."

One indication of the confidence of the oil companies in the amount and likely profitability of North Slope oil are joint plans to build a $900 million, 800-mile pipeline across Alaska to a warm-water port in the south. "This line will definitely be built, and we'll start as soon as we get needed clearances from the Federal Government," reports Atlantic Richfield's Mr. Bradshaw. A formal application to the Bureau of Land Management, which must clear the pipeline route over Federal land, is being prepared, he adds.

Mr. Bradshaw says the planned 48-inch diameter Trans-Alaska pipeline could carry up to 2 million barrels of oil daily with appropriate pumping stations and storage capacity. It will handle 500,000 to 700,000 barrels of daily output on scheduled completion in early 1972, but will be expanded as markets develop, he reports.

Atlantic Richfield estimates that California alone will have a 500,000-barrel-a-day crude oil deficit by early 1972, he adds. He concedes that other companies have asked to join Atlantic Richfield, Humble and British Petroleum in building the common carrier line, but he declines to identify them.

"We expect to put this oil into East Coast markets by 1975," he reports, "and our calculations show that it will be able to compete very favorably with other domestic crudes." This will likely involve another $1 billion investment if a pipeline is used, regardless of whether it's a transcontinental line from the West Coast to existing systems in the eastern part of the country, or a line down Canada's MacKenzie River valley, he says. Ice-breaking tankers, another option, would be a lower-cost method of moving the oil to the East Coast, he adds.

Possible Sales in Europe

Humble Oil has sliced the giant 115,000-ton tanker S.S. Manhattan into five parts and has three shipyards beefing up its hull with an ice-breaking bow, ice belt and protection for the rudder and screws.

In June, the tanker, owned by Seatrain Lines Inc., will start for Prudhoe Bay to test the Northwest Passage through the Arctic Islands. If it's successful, ice-breaking tankers up to 250,000 tons and costing up to $50 million are likely to be built. "We'd like to get some North Slope oil directly into Western Europe, if ice-breaking tankers prove feasible," reports Michael L. Haider, chairman of Jersey Standard. To prepare for loading tankers at Prudhoe Bay, scientists of the University of Alaska are spraying water (which instantly freezes) on huge ice islands about 20 miles into the Arctic Ocean, hoping to add enough weight so they'll permanently ground on the ocean bottom to serve as mooring terminals.

Temperatures on the Slope last winter dropped to as low as 72 below zero and winds hit hurricane force of 100 miles an hour, packing engines and equipment with such hard snow that it had to be chipped out by hand. The sun stayed below the horizon for four months, causing a high turnover on the 12-hour day, seven-day-week, four-to-six-week work shifts on the Slope.

By contrast, the sun will shine three straight months this summer, with temperatures reaching 100 degrees above, turning the Slope into vast lakes and rivers and stirring up clouds of mosquitoes.

"We expect North Slope oil to be more profitable than that from the Middle East, despite much higher production and transportation costs," asserts BP's Mr. Wartham, a veteran of Middle East operations that have provided his company with about one-fifth of the Free World's known crude oil reserves.

North Slope production costs may range as high as $1 to $1.20 a barrel, compared with only 10 cents to 20 cents a barrel in the Middle East, he estimates. He notes, for example, that North Slope oil comes up at about 160 degrees Fahrenheit, and that some means will have to be found to cool it so that it won't melt the permafrost. Drillers report they're already having troubles with stuck pipe and collapsed casing in the permafrost even when they use chilled "mud" (a chemical mixture) or air to cool the drilling bit.

BP reports its drilling costs are running $1 million a well on the North Slope, and Atlantic Richfield says the "Susie No. 1" dry hole it drilled on its first test on the Slope cost $4.5 million. Most companies expect cost of wells to develop the Prudhoe Bay field will be much more modest. However, it's estimated that oil companies will have up to $500 million invested on the Slope by year-end—BP is spending about 20 million a month and says that may double by year-end.

Cost of transporting North Slope oil to the West Coast by pipeline and U.S.-flag tanker will likely be about $1.10 a barrel, indicating a wellhead price of about $1.80 a barrel for the medium-grade crude in the Prudhoe Bay field. That compares with about $1.50 to $1.80 for comparable Middle East grades, and Middle East governments take more than half the profit from all output there, while U.S. crude production carries a 27 1/2% depletion allowance on the gross that can eliminate taxes on up to half of net income.

A production rate of 500,000 barrels a day and a wellhead price of $1.80 a barrel would mean the North Slope would produce as much in mineral riches in a little over one year as the about $200 million in gold taken out of the Klondike in its entire history.

Nomination of Acreage

Oil companies have until June 20 to nominate acreage they'd like to bid on next September. Pedro Denton, chief of the mineral section of the state's division of Lands, says only tracts "receiving the most significant interest" will go on the block.

But the sale is likely to be only the beginning. The state has claimed title to millions of acres south of Prudhoe Bay under its statehood act. Pending legislation in Congress would resolve Eskimo and Indian claims and end a freeze on transfer of Federal land to the state. Mr. Denton says the state then plans to offer this land for competitive bids. This, he adds, will invalidate noncompetitive claims that have been filed on the same land with the Federal Government, a move some disgruntled Alaskans plan to oppose.

The same bill would permit the Federal Government to open to bid the vast 23-million-acre Naval Petroleum Reserve No. 4, which borders the present exploration area on the

several shares that had been sold earlier.

Despite the profit-taking yesterday, gainers on the New York Stock Exchange managed to show a moderate lead over decliners, with 7[illegible] issues up and 6[illegible] down at the close.

Big Board Volume Down

Volume on the Big Board slowed to 14,[illegible] shares from 15,[illegible] Wednesday, which was the highest since Dec. [illegible] and among the busiest sessions in the exchange's history.

Institutions, which accounted for a good part of Wednesday's activity, were less active yesterday. Trades of 10,000 shares or more, a measure of their dealings, totaled [illegible], down from the near-record level of 113 the previous day.

Jersey Standard Unit to Send Oil Tanker Through Northwest Passage in Test Run

By JOHN D. WILLIAMS
Staff Reporter of THE WALL STREET JOURNAL

NEW YORK—In mid-July, as part of a $40 million gamble, a big oil tanker will start a voyage from Philadelphia via a polar route north of Canada to the North Slope of Alaska at Prudhoe Bay. And then it is to come back.

Humble Oil & Refining Co., of Houston, a subsidiary of Standard Oil Co. (New Jersey), is betting the test will prove the feasibility of moving oil year-round from the new Alaskan fields to the East Coast of the U.S.

The SS Manhattan, specially fitted as an icebreaker, is scheduled to bull its way through the ice floes of the famous Northwest Passage on a 28-day roundtrip. T. J. Fenn, general manager of Humble's marine department, said if the experiment is successful, the company will know it by October at the earliest. If the results are negative, "we'll know faster than that," he said. The odds are long, he conceded. For example, the Manhattan's twin propellers may fail in the ice.

But the payoff will be high if it works. Jack F. Bennett, general manager of Humble's supply department, estimated that moving the Alaskan oil by sea to the East Coast would be 60 cents a barrel cheaper than via a transcontinental pipeline.

Humble decided on the venture last December. In mid-January it contracted to charter the 115,000-ton Manhattan—the largest U.S. tanker—from Seatrain Lines Inc. for two years at a total charge of about $10 million. Humble may renew the charter and has an option to buy the 940-foot-long vessel.

This past winter the Manhattan was sliced into four sections, three of which were towed to shipyards for modifications at Mobile, Ala., Newport News, Va., and Bath, Maine. A new bow with two-inch-thick steel plates has been built to help slice through the ice. Other sections have a special 1½-inch-thick steel belt to ward off the pressure of ice on the vessel's sides.

The various modification costs will bring the cost to about $30 million.

The powerful 43,000-horsepower Manhattan is currently being rejoined at a Chester, Pa., shipyard and will be checked out early next month before starting the 4,500-mile voyage. This is half the distance it would take to go to Alaska via the Panama Canal. In any event, the Manhattan—now 1,005 long, or 65 feet longer than prior to her refitting—is too large for that canal's locks. And her new weight is 150,000 tons, 9,000 more than before.

If the gamble pays off, Humble plans to build six ice breaker tankers, each of 250,000-ton size, for a total cost of $500 million, Charles F. Jones, Humble's president, told a press conference here. This would be more than twice the cost if the tankers were built in Japan. U.S. law requires that vessels serving U.S. intercoastal ports be crewed by U.S. labor and built in U.S. shipyards.

Mr. Jones speculates that if Humble's concept proves itself other U.S. oil concerns would build up to 30 new tankers by 1980, enlarging the current U.S.-flag oil tanker capacity by 3½ times.

Humble officials made it clear how much of a gamble the project is. M. A. Wright, Humble's chairman, said that Atlantic Richfield Co. and BP Oil Co. have elected to take "a piece of the option at $1 million each," as they join the Northwest Passage experiment. Mr. Jones, the president, said, "We're rolling for a seven on this cast (of the dice) and not for a point."

Alaskan oil production from the North Slope area is expected to begin in the early 1970s at a time when oil flow will begin to decline in the lower 48 states. By 1980, Humble officials predict, the total flow from the Alaskan area will be about two million barrels a day—equal to the current consumption in all of New England, New York and New Jersey.

Should the polar sea route test fail, Humble officials said they would consider pumping the oil across Canada and the U.S. via a new pipeline.

Humble, Atlantic Richfield and BP Oil have already decided to build an 800-mile, $900 million pipeline from the North Slope to the southern coast of Alaska. Pipe has been ordered for delivery starting in August; completion is slated for early 1972. Crude oil coming down via this line will be shipped to Hawaii and West Coast markets.

The Manhattan will carry two helicopters on her deck. These planes will fly ahead of the vessel to test ice conditions and help choose the most favorable route. Two U.S. Coast Guard vessels will accompany the Manhattan to lend assistance, if needed.

DEFENDANT'S
EXHIBIT
166

THE WALL STREET JOURNAL
Page 5
June 4, 1969

DEFENDANT'S EXHIBIT 167

32 THE WALL STREET JOURNAL, Thursday, July 24, 1969

Three Oil Companies to Study Feasibility Of Building First Coast-to-Coast Pipeline

By a WALL STREET JOURNAL *Staff Reporter*

NEW YORK—Three major companies exploring for oil on Alaska's Arctic North Slope announced they'll make a feasibility study of building the nation's first coast-to-coast oil pipeline.

The study will consider construction of a large-diameter crude oil pipeline from the Puget Sound area of Washington to the Eastern Seaboard, by way of Chicago, they said. It would be about 2,600 miles long.

The project was announced jointly by Atlantic Richfield Co.; BP Oil Corp., U.S. operations subsidiary of British Petroleum Co.; and Humble Pipe Line Co., a subsidiary of Standard Oil Co., (New Jersey).

Likely cost wasn't disclosed. But in an interview earlier this year, Thornton F. Bradshaw, president of Atlantic Richfield, estimated such a line would probably cost over $1 billion.

The three companies are already planning to build a $900 million, 48-inch diameter crude oil pipeline from the North Slope to the warm water Alaskan port of Valdez. From there, oil would be shipped to the U.S. West Coast by tanker.

The U.S. transcontinental line is only one of three methods being considered for moving Alaskan oil to the eastern U.S. Humble is also planning next month to send an ice-breaking tanker from Philadelphia through the "Northwest Passage" to Alaska to test feasibility of that method of supplying the East Coast. And several companies are also studying the feasibility of a crude oil pipeline through Canada from the North Slope.

DEFENDANT'S EXHIBIT 168

THE WALL STREET JOURNAL, Tuesday, April 1, 1969

Northern Natural Gas Plans Major Canada Pipeline

Cost of System to Transport Canadian Gas to the U.S. Put at About $1.4 Billion

Government Approval Needed

By a WALL STREET JOURNAL Staff Reporter

OMAHA, Neb.—Northern Natural Gas Co. is seeking to build a major pipeline system in Canada at a cost of about $1.4 billion to transport Canadian gas to the U.S., W. A. Strauss, chairman and president, said.

The total cost, to be spread over a five-year period, will be met in part by "major" participation of Canadian companies, he added. The cost to Northern Natural wasn't disclosed. A spokesman said that required governmental approval for the project was being sought.

However, Mr. Strauss said that plans call for construction of two "large diameter" pipelines from the producing areas in Alberta and the Northwest Territories to Northern's distribution system in Minnesota. The distance from the Minnesota pipelines to the province of Alberta is about [illegible] miles and about [illegible] miles to the Northwest Territories.

To implement plans for participating in the development of Canadian natural gas, Mr. Strauss said, Northern Natural has acquired a majority stock interest in Consolidated Pipe Lines Co., Calgary, Alberta. Terms of the purchase, made from a group of investors, weren't disclosed.

Organized in [illegible], but existing at present only as a "paper" company, Consolidated Pipe Lines has the right to construct and operate pipelines in Canada, subject to government approval.

In recent years, considerable oil and gas-exploration activity has taken place in Canada's Northwest Territories with many major oil companies participating in the search for additional reserves.

Currently, Northern Natural Gas is offering advance payments and other incentives to develop natural-gas reserves for export to the U.S., Mr. Strauss said. He added that "negotiations are currently in progress with a number of producers and we are optimistic that sizable reserves will be dedicated within the next few weeks."

The current program represents Northern Natural's second effort to import Canadian gas. In [illegible], the company sought Federal Power Commission approval of a plan to bring Canadian gas into its system. However, the Federal agency turned down that application in favor of a similar proposal made by Great Lakes Pipeline Co.

That decision was appealed to the courts and subsequently remanded to the FPC for further hearings, scheduled to be resumed June 16 before a commission examiner.

Northern Natural Gas operates in the Midwest with its principal distribution lines in Minnesota, Iowa and Wisconsin. Gas supplies are obtained from Southwest producing areas.

DEFENDANT'S EXHIBIT 169

THE WALL STREET JOURNAL
Page 2
June 18, 1969

Peoples Gas Unit Plans To Buy Midwest Area's First Gas From Canada

WSJ, p.2, 6/18/69

By a WALL STREET JOURNAL *Staff Reporter*

CHICAGO — Natural Gas Pipeline Co. of America, subsidiary of Peoples Gas Co., plans to purchase 155 million cubic feet of Canadian gas daily beginning Nov. 1, 1970, George P. Garver, Natural Gas Pipeline president, said.

If approved by the various regulatory agencies, the arrangement will mark the initial entrance of Canadian gas into the Midwest market. Heretofore the area has relied on domestic gas produced in the South and Southwest.

The gas will be purchased from Great Lakes Gas Transmission Co., which is supplied by Trans-Canada Pipe Lines Ltd., Toronto. Price of the gas wasn't disclosed.

To minimize Natural's capital investment, the company has arranged to deliver the additional gas to the Chicago area by using facilities of Michigan Wisconsin Pipe Line Co. Michigan Wisconsin will accept deliveries of gas from Great Lakes Transmission and then, in turn, make an equal amount of gas available in Chicago to Natural Gas Pipeline.

DEFENDANT'S EXHIBIT 170

WALL STREET JOURNAL
Page 12
December 17, 1969

Alberta Agency Backs Northern Natural On Bid to Export Gas to U.S. Midwest

By a WALL STREET JOURNAL Staff Reporter

CALGARY—The Alberta Oil and Gas Conservation Board has decided to allow Northern Natural Gas Co. of Omaha to export 1.886 trillion cubic feet of natural gas from the province to the U.S.

The decision, subject to approval by Alberta's provincial cabinet, will allow export of the gas during a 20-year period, beginning Jan. 1, 1971.

Northern Natural, through its Canadian affiliate, Consolidated Natural Gas Ltd., Calgary, plans to export the gas to customers in the U.S. Midwest through an [illegible]-mile pipeline. The pipeline is to be built by Consolidated Natural from Empress, Alberta, to North Branch, Minn., at an estimated cost of [illegible] million.

The gas-export plan also is subject to federal approval by Canada and the U.S.

Consolidated Natural had asked that it be allowed to export about 2.2 trillion cubic feet of gas during a 20-year period and, at hearings held by the Alberta agency last summer, the company's bid was opposed by Trans-Canada Pipe Lines Ltd., which argued that there wasn't enough gas in the province to support another pipeline.

Earlier this month, Trans-Canada received Alberta's approval to export another 2.2 trillion cubic feet of gas during the next 25 years, bringing Trans-Canada's total to 21.4 trillion cubic feet over a period extending to Oct. 31, 1994.

Trans-Canada plans to begin moving its additional gas to the U.S. Midwest by Nov. 1, 1970, subject to approval of the Canadian and U.S. governments.

Yesterday, in announcing its decision, the Alberta agency said it had considered Trans-Canada's opposition but that it didn't believe "that the public interest would be adversely affected by the project" of Consolidated Natural.

The board also said that it took into account the "assessment of reserves, the gas-purchase contracts and the manner in which the gas pools will likely be produced."

The proposed source of Consolidated Natural's gas is the Strachan-Ricinus-Phoenix area and the Kaybob South Beaver Hill Lake Formation A pool. Both are in west-central Alberta.

The Alberta board said it was "satisfied that the reduced volume of 1.886 trillion cubic feet of gas is surplus to the present and future needs of the province and the existing permanent commitments."

DEFENDANT'S EXHIBIT 171

24 THE WALL STREET JOURNAL, Friday, December 15, 1967

Consumers Power Announces Plans For Atomic Plant

Dow Chemical Will Be Chief Customer of New Facility; Cost Put at $267 Million

Completion Is Slated in 1975

By a WALL STREET JOURNAL *Staff Reporter*

MIDLAND, Mich.—Consumers Power Co. said it plans to build a $267 million dual-purpose nuclear power generating plant here. Its chief customer would be Dow Chemical Co.

The facility, due to be completed in 1975, will be capable of generating 1.2 million kilowatts and 4 million pounds of steam per hour, with two nuclear reactors.

James H. Campbell, Consumers Power president, said the company has signed a long-term contract with Dow to provide all of Dow's electrical power needs from the new facility and also to provide Dow with the 4 million pounds of steam per hour for its heating and industrial needs.

Dow currently owns and operates its own coal-fired power and steam generating station, which will be closed when the nuclear plant goes into operation. Dow uses vast amounts of electric power to electrolyze brine in its chemical processes, and uses steam to evaporate brine solutions to obtain certain chemicals.

Terms Aren't Given

Neither company would disclose terms of the Dow contract, although Carl A. Gerstacker, Dow chairman, said the power and steam contract with Consumers Power is "the largest contract Dow has ever signed, either buying or selling." It was learned Dow will use about 200,000 kilowatts of the nuclear plants's 1.2 million-kilowatt capacity, with the rest of the power going into a Michigan power pool of which Consumers Power and Detroit Edison Co. are principal members.

The nuclear plant will be entirely owned and operated by Consumers Power, Mr. Campbell said. He said the company will need some type of outside financing for the project, but he declined to say what that financing might be.

Consumers Power recently disclosed plans to build a $186 million pumped-storage plant near Luddington, Mich.

Power for Luddington Plant

It is expected that excess power from the nuclear plant in low-demand time periods will be used to power equipment at the Luddington facility.

Mr. Campbell said the plant will be among the world's first privately owned, dual-purpose nuclear power generating plants. The plant here will be one of the largest yet constructed in terms of electrical output, he added.

He indicated the project wouldn't have been feasible without the contract with Dow.

Consumers Power said the Midland plant's two reactors will be of the type already in use elsewhere and won't represent any innovation in that field. Consumers Power already operates one nuclear plant and has another under construction. The building of the facility here will be subject to Atomic Energy Commission approval, the company said.

DEFENDANT'S EXHIBIT 172

THE WALL STREET JOURNAL
Page 10
March 20, 1969

Jersey Standard Joins List of Companies To Make Nuclear Fuel

Subsidiary to Build Plant in 1970 In Washington State; Research Assigned to Battelle Institute

By a WALL STREET JOURNAL *Staff Reporter*

NEW YORK—Standard Oil Co. (New Jersey) joined the growing parade of private companies planning to manufacture fuel elements for nuclear reactors.

A subsidiary, Jersey Enterprises Inc., said it will build in 1970 in the Richland-Pasco-Kennewick area of Washington State facilities for development and fabrication of nuclear fuels.

Jersey Enterprises also engaged Battelle-Northwest Institute, the Richland, Wash., branch of Battelle Memorial Institute, to carry out nuclear fuel research and development prior to building the facilities. Richland is the site of the Atomic Energy Commission's Hanford Laboratories. Battelle is a nonprofit research and development organization headquartered in Columbus, Ohio.

Jersey Standard becomes the third oil company to announce nuclear fuel plans. The others are Continental Oil Co. and Kerr-McGee Corp. The project would be the ninth such private venture, involving a total of 11 companies. Nuclear fuel elements were fabricated only by the AEC until a few years ago.

Jersey Standard announced earlier this month plans for the initial mining and processing of its uranium ore reserves in South Texas.

The Jersey Enterprises project will initially develop uranium and plutonium fuel elements for use in light-water nuclear reactors, the type used commercially by electric utilities. But it also expects to later develop elements or so-called "fast breeder" reactors. These reactors, still in the research stage, will operate at much higher efficiencies, and will produce new fuel faster than they consume other fuel. Jersey also will evaluate chemical reprocessing of nuclear fuel elements.

Jersey's initial outlays for nuclear fuels research will involve just $1.5 million. But in disclosing the plans, Sen. Jackson (D., Wash.) asserted the project is "the first step in a long-range program designed to enable Jersey Standard to become a significant factor in the production and distribution of nuclear fuels to utility plants."

NUCLEONICS WEEK-January 15, 1970

IN 1970: 23 UTILITIES WILL ASK BIDS ON 29 NUCLEAR UNITS

If all the U.S. utilities who are planning to ask bids on nuclear power stations this year go nuclear all the way - or even halfway - 1970 could be a respectable year for the nuclear power business. Raymond Freeman, of General Electric's corporate headquarters in New York, told the New York City metropolitan area chapter of the American Nuclear Society this week that 23 utilities were planning to request bids on 29 nuclear units this year with a combined capacity of about 30,000 Mwe. Freeman was not predicting how many would order nuclear. Last year, orders were announced for seven units, totaling about 7,250.Mwe.

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DEFENDANT'S EXHIBIT 174

CHICAGO TRIBUNE
Page 16
January 20, 1970

THE ANTI-ATOM NUTS

In a significant report in Sunday's TRIBUNE, Ronald Kotulak, our science editor, called attention to an alarming increase of opposition to nuclear-powered electric generating plants. Government and utility officials predict a power crisis, with blackouts, brownouts, and electricity rationing, in the late 1970s unless it can be averted by an unprecedented expansion program. The only way to meet the country's growing needs for power, without polluting ourselves to death, is to construct generating plants fueled by atomic energy instead of coal, oil, or gas.

Paradoxically, there is strong opposition to nuclear-powered plants from uninformed or mischievous elements of the population who say they are against pollution. This newspaper has been in the forefront of the fight against pollution of our air and water, and we believe that much more vigorous efforts by government agencies at all levels are required to prevent further degradation of our environment. But the anti-pollution campaign, like many other worthy causes, attracts many well-intentioned but emotionally-disturbed people, as well as busybodies, nuts, and others who are in bad company when they're alone.

Some opponents of atomic energy are incited by subversives whose objective is to destroy the capitalist system. Others are against all technology, like the early 19th century followers of an idiot named Ned Ludd in England, who tried to stop the industrial revolution by smashing the machines.

A modern coal-fired generating plant with a capacity of 1 million kilowatts emits 200 tons of sulfur dioxide and 30 tons of nitrogen oxides each day. The burning of coal, oil, and natural gas adds 6 million tons of carbon dioxide and 1 million tons of carbon monoxide to the atmosphere each year. Atomic plants produce no air pollutants. There is no possibility of a nuclear explosion in one of these plants. A coal-fired plant emits more radioactive materials from its smokestack than a nuclear plant. The used fuel cores of nuclear plants are safely buried, in places where there is no danger of water pollution.

Nuclear plants do discharge water, used for cooling purposes, that is 20 per cent warmer than cooling water discharged by conventional plants. Dr. Glenn T. Seaborg, chairman of the Atomic Energy commission, says the effects of this warm water on fish and aquatic plants are not fully known but are under intensive study. He favors state water quality standards which would have to be met before the AEC would issue licenses.

It is fortunate for this area that the Commonwealth Edison company of Chicago pioneered private nuclear power at its Dresden Island plant, near Morris. It has six other giant nuclear plants nearing completion or under construction which will increase its generating capacity by more than 50 per cent to 13.1 million kilowatts in 1973. It will have the largest nuclear generating capacity in the country.

A constant expansion of electric power generating capacity is essential for the nation's economic growth, on which our standard of living depends. Even more than our standard of living—our survival—depends upon the use of atomic energy for power production. In these circumstances, the government must authorize additional plants when and where they are needed, no matter how much opposition there may be.

DEFENDANT'S EXHIBIT 175

WALL STREET JOURNAL
November 28, 1967

Consumers Power Announces Plans For New Plant

Pumped Storage Facility Set For 1973; Detroit Edison To Share Cost and Output

Outlay to Total $186 Million

By a WALL STREET JOURNAL Staff Reporter

JACKSON, Mich.—Consumers Power Co. said it plans to build a pumped storage hydroelectric plant near Ludington, Mich., on Lake Michigan at a cost of $186 million.

Detroit Edison Co. will pay about half the cost of the plant and will share proportionately in its generating capacity. But the plant will be wholly owned and operated by Consumers Power, according to James H. Campbell, Consumers Power president, and Walker L. Cisler, Detroit Edison chairman.

The plant, scheduled for initial use in 1973, will be capable of generating up to 1,872,000 kilowatts of power. This will make the facility the largest pumped storage hydroelectric plant in the U.S., Consumers Power said. Currently, there are 11 such plants operating in the U.S., and the largest is an 800,000-kilowatt facility in Pennsylvania, the utility said. In addition, there are seven projects under construction, and 46 more—some generating up to 2,000,000 kilowatts—are proposed or being considered, it said.

A pumped storage power plant differs from conventional hydroelectric plants in that it stores electric generating power in the form of water in a reservoir, the company said. In the Consumers Power plant, when water is released from a 27 billion-gallon reservoir the company will build, hydraulic turbines will spin the generators, making electricity. The same equipment will pump water to the reservoir from Lake Michigan by reversing the direction of rotation. Thus the generators become electric motors, driving the turbines as water pumps.

Mr. Campbell likened the water-storage type plant to "a giant storage battery" for quick use at a time of peak demand. "In off-peak hours, when customer demand is lowest—such as late at night or on weekends—water will be pumped from the lake and stored in the reservoir," he explained. "Then, at time of maximum demand, the water will be released, generating electricity on its way back to the lake."

"We'll be able to add significantly to our generating capacity; rapidly if necessary," he added.

DEFENDANT'S EXHIBIT

176

WALL STREET JOURNAL
Page 24
August 7, 1968

FPC Aide Again Approves Con Edison Bid To Build Power Project; Protests Likely

A WALL STREET JOURNAL News Roundup

Consolidated Edison Co. won Federal approval for the second time for a bitterly opposed giant $[illegible] million pumped storage hydroelectric project on the Hudson River near Cornwall, N.Y.

A Federal Power Commission examiner recommended that the New York City utility be permitted to proceed with the project it has sought since Jan. [illegible], 1963. The FPC approved it March 9, 1965, but on Dec. 29, 1965 a U.S. Court of Appeals set aside the Federal license and ordered commission hearings.

Opponents have 30 days in which to protest the ruling, and it is considered likely they will do so. If no protests are filed, and the FPC [illegible]'t order a review of the hearing, the decision becomes final in 40 days.

Charles F. Luce, Con Edison chairman and chief executive officer, said if the license is issued for the Cornwall project, "our company can move ahead rapidly with several phases of our program to improve service to customers."

The project has been contested chiefly by conservation groups. Objections initially were aimed at charges that the plant would mar the beauty of historic Storm King Mountain at a scenic spot on the Hudson near West Point. But Con Edison agreed to put the plant and part of its power transmission lines underground. Opposition has since centered chiefly on such points as potential damage to fish spawning areas.

FPC Examiner Ewing G. Simpson rejected as "not persuasive" arguments that the Con Edison project would be harmful to marine life. He also rejected claims that Con Edison hadn't complied with the Federal Power Act's comprehensive planning requirements regarding development of the Cornwall area. The utility plans public parks both around the inland reservoir and along the now decaying river front near the plant.

Con Edison has estimated it would take about three years from start of construction to have the first hydroelectric turbine in operation, and about four years to have all eight turbines on the line. The project would be capable of generating 2 million kilowatts of power on [illegible]tice, one of the largest pumped storage p[illegible]ts in the world.

Pumped-Storage Theory

The theory behind pumped storage is related to the great fluctuation in daily power use. A reservoir of considerable height above the power plant releases water through the plant's turbines to generate power at peak demand periods of the day. During hours of low power use, electricity from other plants is used to reverse the turbines and refill the reservoir with water from the river.

The reservoir for the Cornwall project would be located 1,[illegible] feet above the Hudson in a [illegible]-acre natural depression between White Horse Mountain and Mount Misery, about one mile southwest of Storm King. It would be at the site of the municipal water reservoir for the town of Cornwall, and Con Edison would build a new water reservoir for the town.

Water would flow to the power plant through a [illegible]-foot long, 40-foot diameter tunnel through the mountain. The plant would be placed in underground galleries hewed out of rock north of Storm King Mountain, on the Hudson's west bank, about 40 miles north of New York. Power lines would travel under the Hudson River and underground three-fourths of a mile on the east bank before surfacing for conventional overhead lines.

Examiner Simpson recommended an additional 1.9 miles of undergrounding of power lines and some altering of the proposed route of overhead lines.

Con Edison asserts that the Cornwall plant would provide extensive protection against a massive power failure such as the great Northeast blackout of Nov. 9, 1965. It says that Cornwall's power could be started up within minutes to meet a sudden emergency.

Mr. Luce said, "The availability of Cornwall to provide a large supply of power at a moment's notice in case of emergency will strengthen the reliability of power supply for the entire Northeastern region of the U.S."

Cite Air Pollution

Delay of the Cornwall project has forced Con Edison to build a [illegible] kilowatt coal-fired plant on Staten Island it otherwise wouldn't have needed, and has prevented scheduled closure of parts of four obsolete coal-burning plants in Manhattan. This has hurt the company's efforts to cut costs and has hampered the city's efforts to reduce air pollution, Con Edison officials assert.

Cornwall will enable Con Edison "to reduce even further our share of the air pollution in the New York City area by shutting down older and less efficient coal and oil burning plants," Mr. Luce said.

The court ruling ordering reconsideration of the Cornwall project was considered significant because it forced the FPC to consider esthetic and conservation issues in granting licenses for power projects. But it also brought about charges from some in the power industry of excessive opposition by conservation interests being to the detriment of power users.

DEFENDANT'S EXHIBIT 177

WALL STREET JOURNAL
Page 7
January 19, 1970

TVA Plans to Start $155 Million Project At Raccoon Mountain

Plan Will Include 4 Reversible Pump-Turbine Units With Total Capacity of 1.4 Million Kilowatts

By a WALL STREET JOURNAL *Staff Reporter*

KNOXVILLE, Tenn.—The Tennessee Valley Authority said construction of its $155 million Raccoon Mountain pumped storage hydroelectric project near Chattanooga will begin in mid-1970.

Preliminary studies and investigations for the project have been under way for several years. The system uses power at off-peak hours to pump water to a reservoir where it is stored for making electricity when demand is heavy.

TVA said the project will include four reversible pump-turbine units with a total generating capacity of about 1.4 million kilowatts. The units are planned for an underground powerhouse to be carved out of rock inside the mountain.

The project will include a mountaintop reservoir covering about 800 acres with a tunnel some 30 feet in diameter to drop water from the reservoir to the powerhouse below and out to a nearby lake, TVA said.

The four units are scheduled for operation in 1974 and 1975. Construction will be financed with proceeds from the sale of TVA bonds and with revenue from power sales, TVA said.

TVA said its studies show that additional capacity required to meet system loads during 1974 and 1975 "could be provided at lower cost by the Raccoon Mountain project than with the alternative of steam-electric units."

DEFENDANT'S EXHIBIT
178

TIME MAGAZINE
Page 60
July 26, 1968

THE GEYSERS WITH FUMAROLES IN CALIFORNIA
Power from a leaky crust.

GEOPHYSICS

Percolators in the Earth

While chasing a grizzly bear one day in 1847, Explorer-Surveyor William Bell Elliott wandered into a canyon that looked to him like "the gates of Hell." Huge, spiraling columns of steam hissed out of the ground; the earth trembled beneath his feet. "The Geysers," as he named the hill-rimmed valley 85 miles north of San Francisco, is as awesome as ever. But its frightening bursts of steam are now being harnessed. The canyon is the site of the first commercial geothermal-power plant in the U.S., and the installation has paid off so handsomely in eight years of operation that it has set off a small "steam rush" in the Far West.

As old as the earth itself, natural steam is a familiar source of heat and power in countries as widely separated as Italy, Iceland and New Zealand. The renewed interest in the U.S. springs from a growing population's need for more electricity. In some areas, geothermal steam offers a cheap, ready-made alternative to coal, oil and nuclear fuels, and it leaves no pollutants in the air. At The Geysers, steam-driven turbines produce 58,000 kw. of electricity at a cost 23% below that of nearby conventional generating plants; in a few years, the area could be producing almost 20 times as much.

Prospecting for Steam. The largest and most accessible steam fields are located west of the Rockies, where volcanic activity has brought molten, lava-like rock known as magma close to the earth's surface. The 1,300° F. magma either releases its own trapped water as steam or, like a gigantic coffee percolator, vaporizes water that has seeped down into the earth.

Occasionally steam emerges through fissures in the ground called fumaroles (from the Latin word *fumariolum*, meaning smokehole), and the simplest way to prospect for this geothermal energy is to look for such vaporous leaks in the earth's crust. But in areas where the energy remains trapped underground, geologists must use more sophisticated techniques. One method employs infra-red aerial photography. Since the infra-red film is sensitive to heat, geothermal areas are likely to show up lighter in the picture. Another method measures the earth's electrical conductivity, which increases with the presence of subsurface hot water. To tap the subterranean energy, engineers drill with standard oil rigs, going down as little as 600 ft. or as much as 8,000 ft., the depth of the world's deepest steam well at Salton Sea near Brawley, Calif.

The Monster. The job can be dangerous as well as difficult. At The Geysers, a new well erupted with such furious force that the scalded workmen were convinced they had tapped a live volcano. To cool it off, they pumped in cold water until a nearby stream ran dry. Then they tried a concrete plug, without success. "The Monster," as they dubbed the well a decade ago, continues to spout.

Such unrestrained power holds enormous promise. Engineers estimate that by 1980, geothermal energy could be generating as much as 10% of the total electrical output of the U.S. And no matter how much is used, the heat is not likely to be used up. Once scientists master the technology, they should be able to recirculate condensed steam back into the ground, giving virtually unlimited life to wells in states as dry as Nevada. Even without such recirculation, Italy's 64-year-old Larderello geothermal-power plant near Siena, where fumaroles gave Dante earthly inspiration for his Inferno six centuries ago, is still going strong.

DEFENDANT'S EXHIBIT 179

CHICAGO DAILY NEWS
Page 45
January 9, 1969

Earth's own power source

This is Geothermal Resources Well No. 1 in Sonoma County, Calif. There's a steam rush today in the country that had a gold rush 120 years ago.

By Dean C. Miller
United Press International

If man succeeds in tapping and harnessing the giant steam boiler below the earth's crust he will have enough power to run his factories, heat and light his homes, and launch his space probes for centuries.

U.S. companies in recent months have decided to drill seriously for geothermal power locked in the earth's molten center.

The resultant "great steam rush," like the "great gold rush" 120 years ago, was centered west of the Rockies. The rigs are especially active at the geysers about 90 miles north of San Francisco, where Pacific Gas & Electric Co. has been producing electricity since 1960 from steam created by molten rock or magma under the earth's surface.

PG&E plans a $20,000,000 complex capable of generating 250,000 kilowatts, enough to "turn on" San Francisco.

Oil companies also are in the steam race. Occidental Petroleum, Sun Oil and Union Oil are prospecting.

Some scientists estimate 10 per cent of the U.S. electricity will come from such wells by 1980.

The potential is staggering. Power from steam wells will be virtually inexhaustible when a technology permitting recirculation of condensed steam back into the ground is refined.

LIKE NUCLEAR power, geothermal energy is being touted as the energy source of the future. And it has the added advantages of being cheap and non-polluting.

DEFENDANT'S EXHIBIT 180

WALL STREET JOURNAL
Page 19
June 23, 1969

Burning Refuse to Be Used In 'Total Energy' Concept

By a WALL STREET JOURNAL Staff Reporter

NEW YORK — Refuse collected from tenants will provide part of the fuel supplying all electricity, heat and air conditioning for two shopping centers to be built in Joplin, Mo. and Middletown, N.Y.

Two small New York companies announced plans for combining refuse disposal with the so-called "total energy" concept of supplying all energy needs with on-site plants.

Combustion Equipment Associates Inc., a maker of air and water pollution control devices, will design, manufacture and maintain a refuse collection and disposal system for the two projects. It said the system will be "pollution free."

Total Energy Leasing Corp., which owns and leases on-site total energy plants, will lease the refuse system for use in its total energy units at the two shopping centers.

Some European cities, Montreal and the U.S. Navy have constructed plants that generate steam by burning refuse. This steam, in turn, is used for generating electricity and for heating. The new projects, however, would carry the principle a bit further by combining it with the total energy approach.

DEFENDANT'S EXHIBIT
181

Excerpt from transcript of Hearings before the Joint Committee on Atomic Energy, 90th Congress, 2d Session, on Participation by Small Electrical Utilities in Nuclear Power. - (Part 1 - April 30-May 3, 1968).

(Reprinted from April 29, 1968 issue of Electrical World - Copyright 1968, McGraw-Hill, Inc. All rights reserved)

AFFILIATION IS FAST BECOMING A NECESSITY ✓

Consolidation of power systems in the U.S. today is fast becoming a matter of economic necessity.

For the past five years economies of scale have steadily pointed to the merits of better coordinated operation and mutual location, timing, sizing, and ownership of system facilities among neighboring interconnected utilities. The industry has steadily moved in this direction.

Today the tempo has quickened. Impact of the mounting new capital requirements, soaring interest rates, sagging rates of return, and the touchy legalities of coordination for reliability are fast making corporate partners out of friendly neighbors.

The issue today is not so much *whether* to integrate contiguous systems as it is *how* and *when*. Affiliation is getting the nod more often than outright absorption of one company by the other. The reasons are plausible. Affiliation leaves corporate identities intact, minimizes personality and personnel conflicts, maintains local company identity, preserves prestige, and simplifies and accelerates the journey toward the coordinated planning and operation.

These affiliations all tend to optimize operating savings which in some instances, even among groups of limited size, can amount to upwards of $2 million a year. Common purchasing of stock items in carload lots can bring savings of 10-15% and substantial amounts on fuel purchases. Mutual standards offer economics by eliminating minor differences in specifications and settling on fewer types of materials and equipment.

In another area, operation of a mutual engineering and design department, research and development, the consolidation of heavy construction forces, sharing of testing departments, and the operation of mutual standardization and metering laboratories can bring further savings.

All of these considerations soften and can perhaps offset the declining rate of return created by mounting money rates and escalating costs of material and equipment in the face of expanding system needs to keep pace with mounting loads.

But as we see it, perhaps the most far-reaching and significant influence in the creation of affiliations is related to the legal and financial complexities involved in true coordination of power pools and interconnected systems to attain the ultimate in bulk power reliability. It is difficult in the extreme to conceive how agreement could be reached—short of affiliation—among members of a pool or interconnection where extensive reinforcement to the fringe area of a remote system is paramount to the reliability of a nearby metropolitan load center.

And so it is that we say that merger and affiliation of power systems today is no longer a comfortable convenient thing to do, but it is fast becoming a matter of industry necessity.

DEFENDANT'S EXHIBIT 182

New York Times
June 12, 1968

New England Affiliation Slated

Three Concerns Involved

The boards of the Boston Edison Company, Eastern Utilities Associates and the New England Electric System had approved a plan to combine under a single parent organization, the Eastern Electric Energy System, the companies announced yesterday, continuing the trend toward "affiliations" of utilities on a regional basis.

The new company would be a Massachusetts business trust with operating subsidiaries serving about 1.6 million electric and gas customers in 261 towns in parts of Massachusetts, New Hampshire and Rhode Island. The announcement was made jointly by Charles F. Avila, chairman of Boston Edison; Guido R. Perera, president of Eastern Utilities; and William Webster, chairman of New England Electric.

The three executives said the decision to unite followed an analysis of studies made over the last several months by both the individual companies and outside consultants. The studies indicated such a move would be "in the interest of shareholders and customers and

UTILITY CONCERNS PLAN AFFILIATION

Continued From Page 61

should produce benefits to the New England regional economy."

Under the terms of the agreement, stockholders of Boston Edison common would receive 1.85 shares of Eastern Electric Energy for each share held. Holders of Eastern Utilities would receive 1.134 shares of the new company's common stock for each share held after giving effect to its 2 for 1 stock split on last May 31 and owners of New England Electric common would receive one share of Eastern Electric Energy for each share held.

Year Needed for Approval

It is expected that at least one year would be required to obtain the necessary approvals of the Securities and Exchange Commission, the Federal Power Commission and the Massachusetts Department of Public Utilities.

Combined assets of the new company as of last Dec. 31 would have been in excess of $1.5-billion, making it the eighth largest power system in the nation. Total operating revenues would have been $487-million and net income would have been about $55-million. It would be the twelfth largest in country in kilowatt-hour sales and 13th in electrical [illegible]

This latest affiliation of utilities continues to bear out the prediction of Donald C. Cook, president of the American Electric Power System, who said that the day is coming when there will be no more than a dozen or so utilities across the nation.

New England Network Seen

Utility observers also looked upon yesterday's announcement as hastening the day of an all-New England utility network made up of Northeast Utilities, itself a relatively new holding company, and the new Eastern Electric Energy, plus various independent companies throughout the six-state area.

In fact, Northeast Utilities, New England Electric and Boston Edison went into lengthy preliminary investigations of a possible affiliation back in 1966. This would have produced a system with assets of more than $2-billion putting it into the top three in size in the industry at that time.

Northeast Utilities broke off negotiations on Jan. 31, 1967 and the three announced then the move "was not intended to bar eventual affiliation but was a temporary action to give Northeast an opportunity to complete internal adjustments arising from its earlier mergers."

18 THE WALL STREET JOURNAL, Tuesday, July 22, 1969

Boards of Iowa P&L And Iowa-Illinois G&E Approve Merger Plan

New Entity, Iowa Energy Corp., Plans to Retire the 2 Utilities' Outstanding Preferred Shares

By a WALL STREET JOURNAL Staff Reporter

DES MOINES, Iowa—Iowa Power & Light Co. and Iowa-Illinois Gas & Electric Co. said directors of both companies approved a plan to merge the concerns into a new corporation to be called Iowa Energy Corp. The merger previously had been approved in principle.

The consolidation plan provides that outstanding shares of preferred stock of the two companies will be retired by the new corporation at the rate of 8,000 shares annually. The preferred shares will be exchanged for Iowa Energy preferred shares on a share-for-share basis with equivalent dividend rates, redemption and liquidation prices and similar rights and preferences, the companies said.

Under terms previously announced, Iowa Energy and Iowa-Illinois common stock will be exchanged on a share-for-share basis, and 1.15 shares of Iowa Energy will be issued for each Iowa Power common share. Iowa Power has 2.2 million common shares outstanding, and Iowa-Illinois Gas has 8.1 million.

The two utilities entered into a memorandum of intent in September 1967 to combine under a holding company arrangement. They attempted to attract other gas and electric utilities in Iowa into joining the plan, but were unsuccessful. The two utilities said last month a merger was being explored as "a possible alternative to the holding company proposal."

DEFENDANT'S EXHIBIT 184

THE WALL STREET JOURNAL
Page 8
November 27, 1968

Ayrshire Collieries Asks Bids of 5 Firms

Coal Concern Invites Offers to Purchase or Merge With It; Replies Expected Next Month

By a WALL STREET JOURNAL *Staff Reporter*

INDIANAPOLIS—Ayrshire Collieries Corp. has invited five companies to submit either sale or merger proposals, according to a letter sent to stockholders.

The five companies weren't named. Plans for either the sale or merger of the coal company were disclosed early this year.

Proposals are expected to be received in December from all five companies, the letter said. But shareholders were told that because of the possibility that any negotiations or agreement will "involve complicated types of transactions," it may be two or three months before additional information can be supplied.

"Because of complications, we believe it's in the best interests of stockholders not to make any further announcement until a definite agreement has been reached for the sale or merger of the company," the letter stated.

Lovett C. Peters, former executive vice president of Cabot Corp., said, "It appears Ayrshire would be more valuable to others than to Ayrshire stockholders." Mr. Peters was hired last February to act as agent in any transaction.

Questioned as to the management's reasons for selling the company, Pierre F. Goodrich, chairman, said, "Proper action by directors includes not only management but also consideration of a sale or merger if it appeared to be in the stockholders' best interests." He declined further comment.

DEFENDANT'S EXHIBIT 185

THE WALL STREET JOURNAL
Page 34
January 22, 1969

Ashland Oil Plans To Buy or Lease Ayrshire Assets

Boards Vote Proposal That Includes the Sale of Coal Royalties to Third Firm

Pact Involves $125 Million

By a WALL STREET JOURNAL *Staff Reporter*

ASHLAND, Ky.—Ashland Oil & Refining Co. and Ayrshire Collieries Corp. said directors approved a proposal involving acquisition or lease of Ayrshire's assets by Ashland.

Ayrshire Collieries produces coal, with operations primarily in Illinois, Indiana and Western Kentucky. The company has substantial reserves west of the Mississippi River.

The announcement said Ayrshire would receive for its assets an aggregate of approximately $125 million, with at least $95 million to be derived from sale of reserved coal royalties. The balance of the sale price would be paid by Ashland in cash or common shares having the same market value.

Reserved coal royalties, including mining rights and related mining equipment, will be sold by Ayrshire to third parties, and thereafter operated under a lease providing for the payment of royalties on coal produced.

Such "production payments" are common in transactions involving large reserves of oil or minerals in the ground, and have been used in other recent acquisitions of coal companies. A spokesman for Ashland said a leasing arrangement is relatively new in the coal industry, but is common in the hard minerals industry.

The proposal contemplates that Ayrshire will pay from the proceeds of the sale approximately $19,625,000 principal amount of long-term debt of Ayrshire and its subsidiaries. On liquidation, Ayrshire shareholders are expected to receive, after payment of certain expenses and [illegible] related to the sale, cash or cash and [illegible] worth an aggregate value [illegible]

Orin Atkins, president of Ashland, and Pierre F. Goodrich, chairman of Ayrshire, said the transaction is subject to completion of definitive agreements providing for the sale by Ayrshire of all of its assets, approval by Ayrshire shareholders, receipt of a tax ruling, and other necessary approvals.

Ayrshire in 1968 had sales of approximately $60 million. The company produces approximately nine million tons of coal annually.

Ashland Oil, which had 1968 sales of more than $1 billion, refines and markets petroleum products, petrochemicals and chemicals.

Mr. Atkins had told the Ashland annual meeting Monday that a number of other companies were also bidding for Ayrshire. He said the coal company had coal reserves of more than 2 billion tons.

Ayrshire is located in Indianapolis.

DEFENDANT'S EXHIBIT 186

THE WALL STREET JOURNAL
Page 7
April 24, 1969

Metal Climax, Ayrshire Sign Merger Accord

Acquisition of Coal Producer By Metals Firm Valued at Minimum of $62.6 Million

Boards and Holders to Vote

By a WALL STREET JOURNAL Staff Reporter

NEW YORK—American Metal Climax Inc. and Ayrshire Collieries Corp. said they signed a letter of intent "looking toward" the merger of Ayrshire into Metal Climax in a transaction currently valued at a minimum of $62.6 million.

The acquisition of Ayrshire, an Indianapolis-based coal producer, would mark Metal Climax's first move into the coal business. Metal Climax is a major producer, fabricator and marketer of metals and minerals, including molybdenum, potash, copper, lead, zinc, iron and aluminum.

Talks aimed at the acquisition of Ayrshire or the leasing of its assets to Ashland Oil & Refining Co., Ashland, Ky., were called off earlier this month. At that time, Ayrshire said it was holding discussions with another company, which it didn't identify.

Under terms of the Metal Climax-Ayrshire agreement, Ayrshire stockholders would receive one share of a new class of Metal Climax convertible preferred stock for each of the 700,000 Ayrshire common shares. The new Metal Climax preferred would have a dividend rate of $4 a share through 1971 and $5.25 a share thereafter. It would be convertible into the company's common stock on a formula based on the price of the common between now and May 31, within a convertibility range of 1⅓ to 1 2-3 common shares for each preferred share.

On the basis of Metal Climax's closing price on the New York Stock Exchange yesterday of $53.75, up $1.125, the proposed transaction would have a minimum value of $62.6 million and a maximum value of $69.5 million.

The agreement is subject to ratification by directors and shareholders of both companies. It's contemplated that the transaction would be tax-free to Ayrshire holders.

Ayrshire mines coal in Indiana, Illinois and Kentucky, predominantly by the open-pit method. In the fiscal year ended June 30, 1968, the company earned $4.3 million, or $5.24 a share, on sales of $59.7 million; in the first half of fiscal 1969, the company earned $1.1 million, or $1.45 a share, on sales of $22.6 million.

Coal production from its nine mines is about nine million tons a year. Two new mines are under development and annual production is expected to increase to about 15 million tons by 1972. The coal is sold primarily to electric utilities.

Metal Climax earned $67.4 million, or $4.38 a share, in 1968 on sales of $878.6 million.

Last year, Kennecott Copper Corp., the largest U.S. copper producer and a major foreign copper producer, acquired Peabody Coal Co. in a diversification move.

DEFENDANT'S EXHIBIT 187

For your

Air pollution authorities urge use of "clean-burning" natural Gas.

Today, more and more apartment building owners are turning to Gas heat. Things stay cleaner inside and out.

What you've read in newspapers, magazines and heard on television is true. Air pollution is fast becoming more of a threat than ever. Like most of our major cities, Chicago is facing a big problem.

Polluted air is dangerous. It isn't something one person can suddenly stop. It's the concern of all of us. And more and more apartment building owners are turning to natural Gas. You see, natural Gas burns cleaner. That's why natural Gas is now recognized as a good way to help keep city air cleaner. And air pollution authorities are saying as much in other large urban centers.

If you own an apartment building, it makes good sense to consider clean-burning natural Gas. Gas makes good money sense too, because Gas is economical. Your tenants will be happier too, because natural Gas helps to keep apartments clean. And with natural Gas, you can be sure you will be doing your part for a cleaner Chicago. Like a fresh idea? This one lets you breathe a little easier.

PEOPLES GAS

CHICAGO SUN TIMES 5/16/67

Gas does the big jobs better for less!

DEFENDANT'S
EXHIBIT
188

1977 THE YEAR OUR CITY DIED.

If the increasing pollution of our air is not reversed, Philadelphians might have to move. Or both adults and children will gasp for fresh air and get sick with dangerous respiratory ailments.

Could this nightmare come true? Yes. The special air pollution report to New York City's mayor warns that this could happen to major cities—including Philadelphia—within 7-10 years. Unless prompt action is taken to bring air pollution under control.

Just a few weeks ago an air pollution alert sounded in Philadelphia. Fortunately, a change in the weather broke up the inversion before pollution reached dangerous levels. But next week or next month, we may not be so lucky.

One important step to reduce air pollution is for industry to change to fuel that does not contain sulfur. A fuel like natural gas, a non-pollutant. And PGW has encouraged this change by reducing gas rates to large users twice in recent months. For facts on big-volume gas rates, or to explore the advantages of using gas, write direct to us. Or call 796-4233.

PHILADELPHIA GAS WORKS

PHILADELPHIA
INQUIRER
12/4/67

DEFENDANT'S EXHIBIT 189

You can heat 2½ houses with modern oil for what it costs to heat 1 house with electricity!

No doubt about it. Just take your oil bill for last winter. Multiply by 2½. That's about what electric heat would cost. Let's say your oil bill was $200. Then, electric heat would cost about $500. You pay $300 more every year. Over a 20-year mortgage your oil savings of $300 a year could add up to over $10,000*. It's easy to see what a fortune you save with oil heat!

You save in other benefits, too. No fuel is cleaner than oil. (Take an electric clock off the wall. Look at the smudge.) No fuel is more powerful. (Oil heats water 5 times faster than electricity.) No fuel is safer. (With oil — no red hot wires all over the house.) Individual room temperatures? You can have that with any fuel. But what for? It means running around changing seven or eight thermostats all the time and keeping doors closed between rooms! Who needs it?

Why pay so much more and get so much less? Stay with modern oil heat and count your blessings. Count your money, too!

*Compounded at 5%

OILHEAT
YOU CAN DEPEND ON IT

LOCAL CHAPTER NAME AND ADDRESS

We're helping Main Street switch to nuclear power.

Nearly half of recent generating capacity commitments are nuclear. Worthington, a leader in many phases of conventional power generation, is directly involved in the switch.

Our jet gas turbines and diesel engines can supply the energy to start up nuclear plants. Our control valves, boiler feed pumps, motors and feedwater heaters are in plants under construction. And we've shipped the largest twin-shell, multi-pressure nuclear steam condenser.

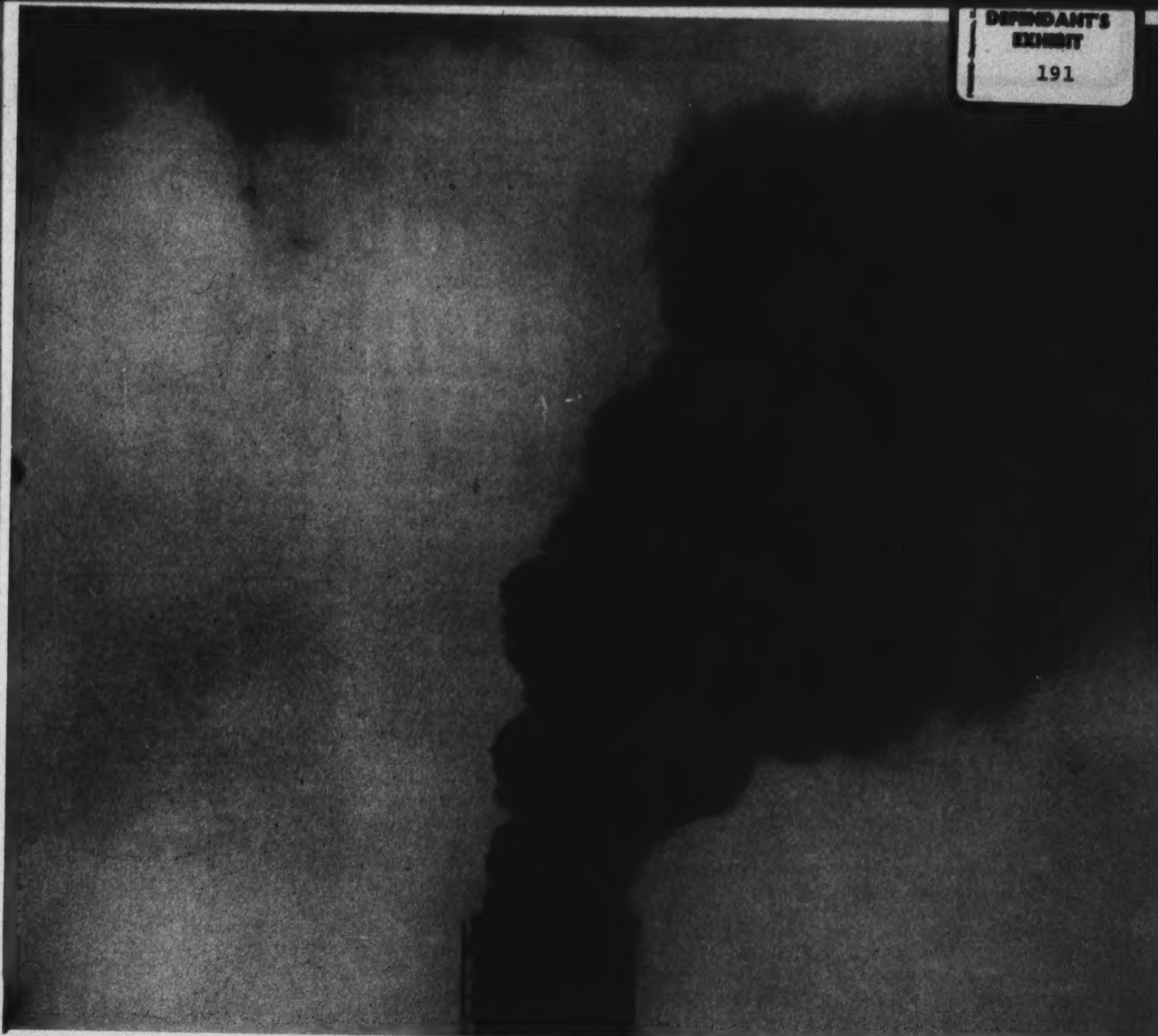
In fossil fuel plants, we've shown the way with many developments in major steam plant auxiliaries. And we have many innovations in our complete turbine, diesel and jet gas turbine generating units used for base load, peaking or emergency standby.

Helping generate power for industry and people is one of many ways Worthington helps serve man's basic needs: for energy, food, water, transportation, and health and sanitation.

WORTHINGTON
SERVING MAN'S BASIC NEEDS WORLDWIDE

1172

DEFENDANT'S EXHIBIT 191



This pollution was caused by burning money.

How much of it was yours?

Where there's smoke, there's incomplete combustion. When it comes from a boiler plant, someone has paid for fuel that didn't burn. What doesn't burn gives no heat. Someone's money has gone up the chimney in smoke. Which makes not only bad air, but very bad economics.

What makes *good* economics is to put in a modern Todd burner with the sonic fuel atomizer—as replacement for older burners (coal or oil), or in new construction. Combustion efficiency with sonic atomization: 98% and often higher. It keeps your chimney smokeless, even with residual fuel oil.

Using sonic energy to boost boiler performance is the first really new development in fuel atomization in 50 years. It is also a Todd exclusive.

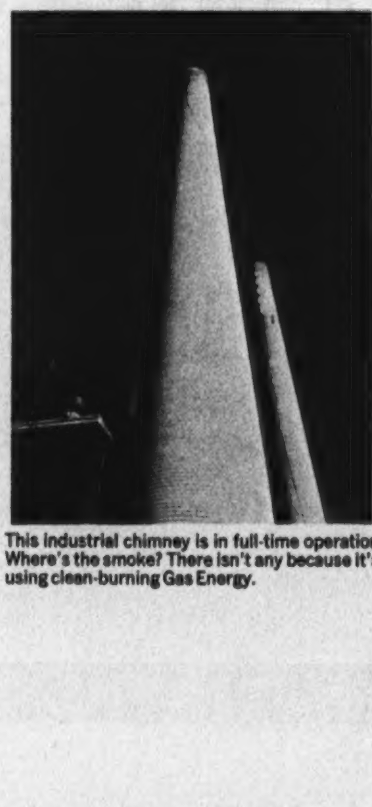
Be selfish. Fight air pollution. Have your engineering department write Todd today for design information. Department F., 120 Park Avenue, New York, N.Y. 10017.

TODD PRODUCTS

DIVISION OF TODD SHIPYARDS CORPORATION
Gas- and oil-burning equipment for commercial, industrial and marine application

DEFENDANT'S EXHIBIT 192

What's Gas Energy doing to make industry nice to be near?



This industrial chimney is in full-time operation. Where's the smoke? There isn't any because it's using clean-burning Gas Energy.

Gas Energy is helping to get rid of plant waste before it becomes a community air pollution problem. By using economical Gas for waste incineration and heat processing, more and more plants are contributing to clean air in their communities.

But Gas incineration is more than good public relations, it's good business. Because Gas cuts operating costs for processing and waste disposal. And high temperature incineration is effective because Gas burns clean. And without odor.

Modern Gas incineration can dispose of liquid, gaseous, and solid wastes. And heat from incineration can be recovered for industrial processing. Or for plant climate control.

The problem of air pollution is receiving public and legislative attention. So industry must solve its diverse and complex problems of gaseous, liquid, and solid waste disposal. And research in the Gas Industry is playing an important role in solving these problems.

But is this really so surprising? After all Gas is almost pure energy.

AMERICAN GAS ASSOCIATION, INC.

1174

DEFENDANT'S EXHIBIT 193

How nuclear science may give America more Gas energy.

It happened in December, 1967. With a muffled boom from the release of energy equivalent to 26,000 tons of TNT. A nuclear explosion that was part of Project Gasbuggy. It was an experiment designed to put nuclear explosives to work on their first peaceful, industrial application.

The explosion took place 4,240 feet underground. Its purpose was to heavily fracture the Gas-bearing rock in a remote area of New Mexico. That way, more Gas could move through the rock and to a wellbore.

With conventional explosives, estimated recovery of Gas at the Gasbuggy site would be about 10%. But a nuclear explosive, by vastly increasing escape space in Gas-bearing rock, was expected to increase recovery to an estimated 70%.

Working with the Atomic Energy Commission and Department of Interior, the Gas Industry is planning for the future. There is great optimism that this and other experiments will make it possible for America to have more energy for better living tomorrow.

But is this all really so surprising? After all, Gas is almost pure energy.

AMERICAN GAS ASSOCIATION, INC.

BOILER CONVERSION?

Get the 5 advantages Gas power-type burners give you in full measure.

Here they are: efficiency, safety, durability, economy, and cleanliness.

You see, Gas power burners work by forced injection of primary and secondary air. This provides perfect control of combustion, regardless of variable chimney drafts. No high chimney or induced draft fan is needed. Just a short vent stack, properly sized.

That's efficiency and economy. So is the way Gas burners come completely assembled for quick and easy installation. Safety? Factory-tested Midco Lo-Blast power burners, for example, come with dual-type constant safety pilots as the standard control system. And other safety systems are also available.

Cleanliness? Nothing burns cleaner than Gas. Or more economically. Gas burners are durable. No replacement worries.

Midco converts an apartment and the service staff is cut by 2/3.

When the University of Chicago bought a hotel for residential use, one of the first steps was conversion to Midco Lo-Blast burners. Instead of three full-time engineers plus two relief men, the 10-story building's heating system is now serviced by one man. And the Midco 6,000,000 BTU/hr burner operates so automatically that 95% of his time is available for other duties. Also reduced: noise and dirt.

Are you converting? Better get details on Midco burners from your local Gas Company Sales Engineer. Or write: Mid-Continent Metal Products Co., 2717 North Greenview Ave., Chicago, Ill. 60614.

AMERICAN GAS ASSOCIATION, INC.
For commercial heating... Gas makes the big difference.

AG-76819—This advertisement appears in Actual Specifying Engineer, March; American School Board Journal, March; American School & University, March; Consulting Engineer, May; Plant Engineering, May; Domestic Engineering, June, 1968.

KETCHUM, MACLEOD & GROVE, INC.

THIS IS A PAR ACTIVITY

DEFENDANT'S EXHIBIT 195

Who offers you 24-hour plant site location service on the 60-mile Illinois Shore?

Peoples Gas, of course.

Look to the Illinois Shore for your new plant site. From Indiana to the Wisconsin state line and west are more than five hundred square miles of industry-rich land called the Illinois Shore. If you're looking for a new company home, it's smart to take advantage of the free 24-hour plant site location service we offer.

In a day or sooner, you'll have all the vital facts. Peoples Gas will put charts, maps, data-processed site and building information at your fingertips. Everything you'll want to know. And experienced personnel will work with you.

Discover the prosperous Illinois Shore. Call or write The Peoples Gas Light and Coke Company, 122 S. Michigan Avenue, Chicago, Illinois 60603; ask for the Area Development Manager. Phone Area Code 312—431-4888.

THE PEOPLES GAS LIGHT AND COKE COMPANY AND NORTH SHORE GAS COMPANY

DEFENDANT'S EXHIBIT 196

the not-so-brief case

for complete chicagoland plant site information

Call Jack Cornelius at Peoples Gas, and he will bring it to your door—tomorrow!!

How do you briefly discuss something as important as a new plant site location? Chances are you don't—not if you want all the facts.

That's why you should rely upon the complete relocation service that a Peoples Gas representative can give you. Because our staff is expert in many fields—real estate, transportation, labor, financing and more—they are uniquely equipped to answer all your questions. Thoroughly. As they apply to you.

We know Chicagoland's Illinois Shore area like no one else. From the Wisconsin border to Indiana and all 500 square miles of industry-rich land in between. Whether you seek an urban, suburban or rural environment, we can find just the site to fit your particular needs.

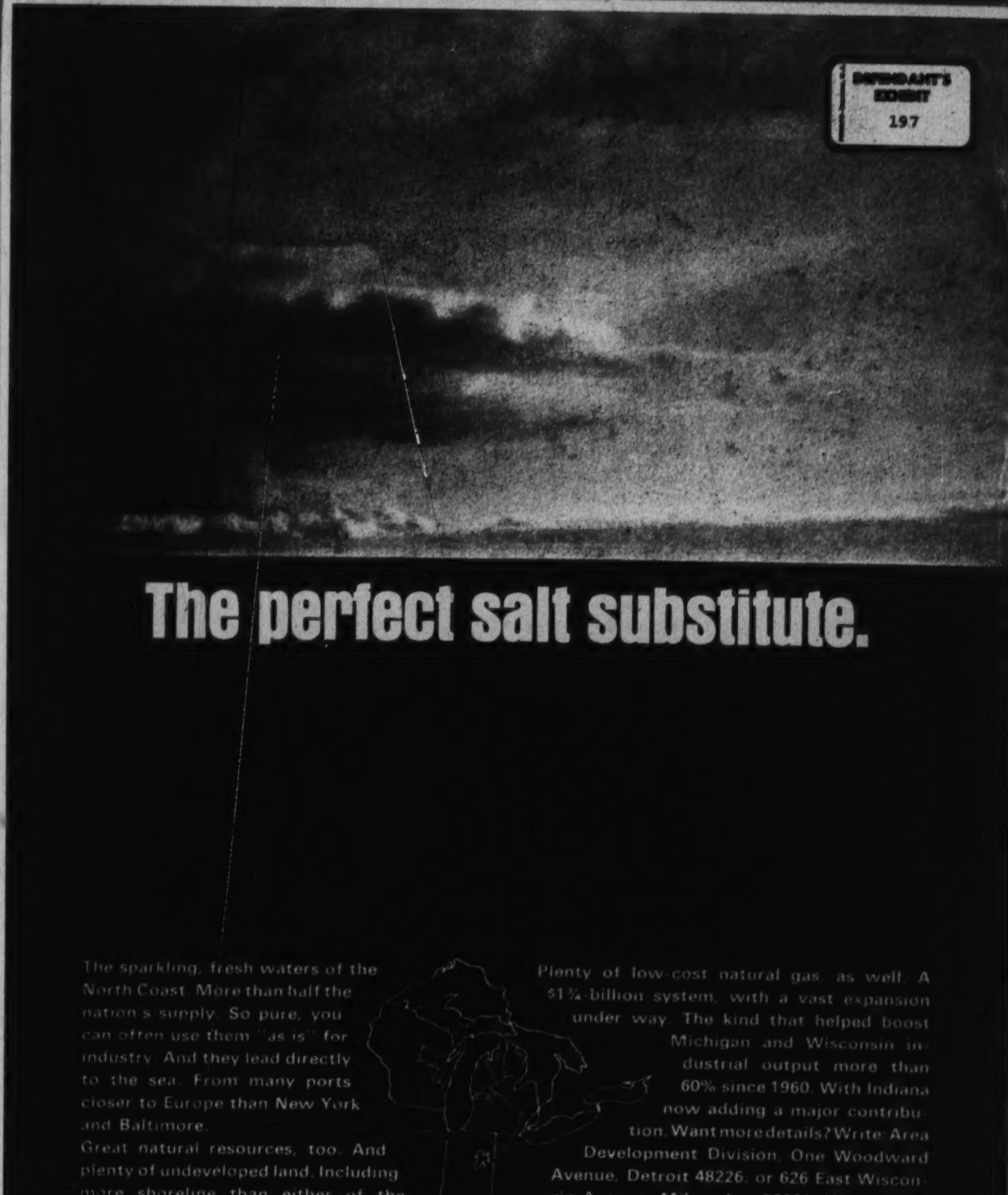
And thanks to our automated selection of plant site information, our staff can pull together loads of information and personally answer your immediate questions immediately, *within 24 hours of your call.*

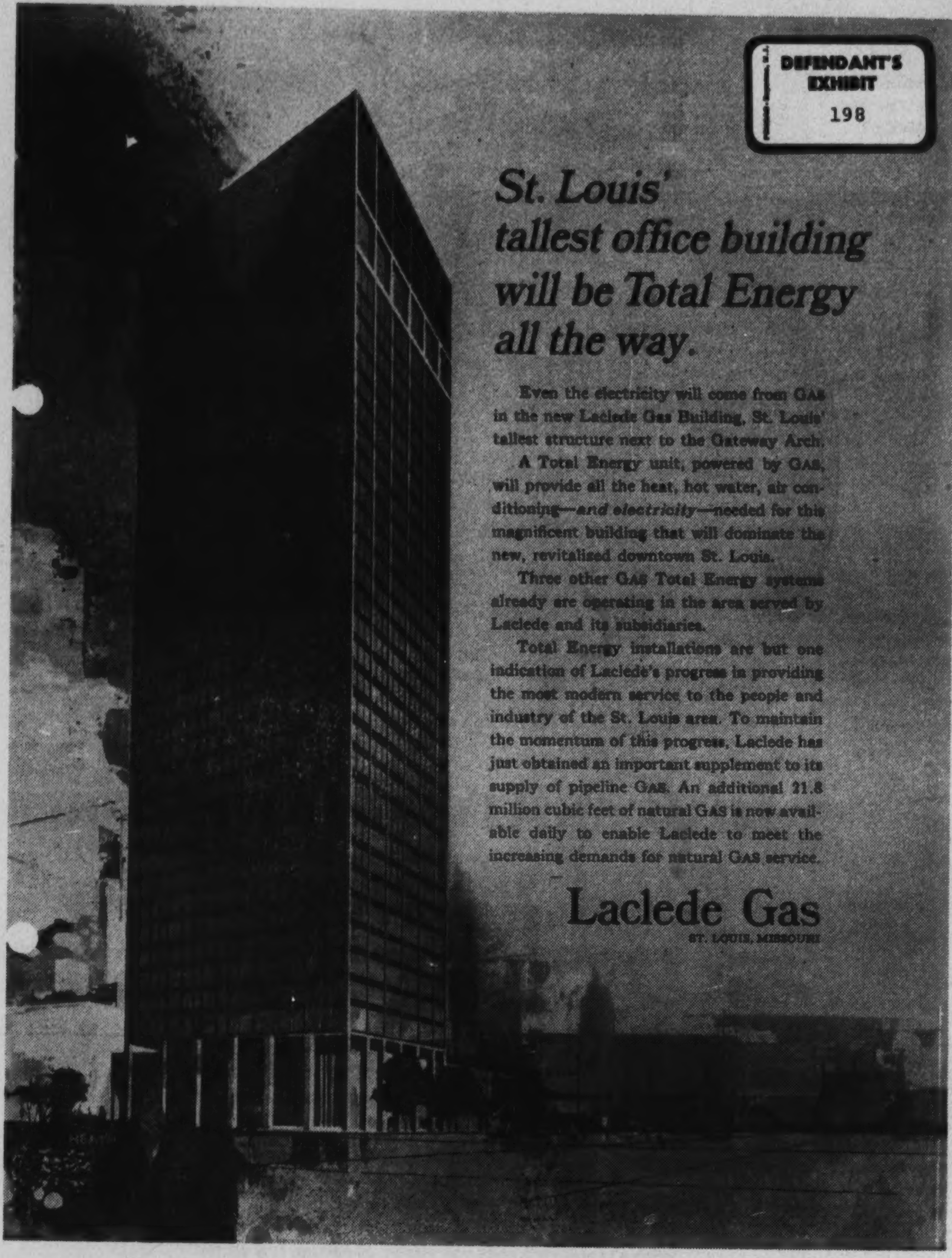
So go ahead—dial 312—431-4888 collect and ask for Area Development Manager, Jack Cornelius. You pick up the phone—he picks up his case.

THE PEOPLES GAS LIGHT AND COKE COMPANY
122 S. Michigan Avenue • Chicago, Illinois 60603

THE PEOPLES GAS LIGHT AND COKE COMPANY AND NORTH SHORE GAS COMPANY

DEFENDANT'S EXHIBIT 197




DEFENDANT'S EXHIBIT 198
St. Louis' tallest office building will be Total Energy all the way.
Even the electricity will come from GAS in the new Laclede Gas Building, St. Louis' tallest structure next to the Gateway Arch.
A Total Energy unit, powered by GAS, will provide all the heat, hot water, air conditioning—*and electricity*—needed for this magnificent building that will dominate the new, revitalized downtown St. Louis.
Three other GAS Total Energy systems already are operating in the area served by Laclede and its subsidiaries.
Total Energy installations are but one indication of Laclede's progress in providing the most modern service to the people and industry of the St. Louis area. To maintain the momentum of this progress, Laclede has just obtained an important supplement to its supply of pipeline GAS. An additional 21.8 million cubic feet of natural GAS is now available daily to enable Laclede to meet the increasing demands for natural GAS service.
Laclede Gas
ST. LOUIS, MISSOURI

DEFENDANT'S EXHIBIT 199

The Savings and Loan that saves with natural Gas.

Blue Island Savings and Loan in Illinois had a problem. They weren't getting their money's worth from their air conditioning system. The fuel bills were too high and the cooling was inadequate. But that all changed when they changed to Gas.

Gas air conditioning is quiet and efficient. And does a small tonnage job economically. The three units in this system effectively provide customer areas, offices, and vault with 21 tons of cooling air. For only 39 cents an hour. And there's a saving on maintenance too. Because low tonnage Gas air conditioners are constructed for durability.

Management at Blue Island was so pleased with the cooling performance of Gas, they decided to use it for heating too. Isn't it time you decided to use Gas cooling and heating? It's the perfect solution for people who know the value of a dollar.

For any kind of installation, large or small, find out why Gas does the best job. Call your local Gas Company Sales Engineer.

AMERICAN GAS ASSOCIATION, INC.

For heating and cooling,
Gas makes the big difference.

AG-77736—This advertisement appears in U.S. News & World Report, November 18; Chain Store Age, November, 1968.
KETCHUM, MACLEOD & GROVE, INC.

THIS IS A PAR ACTIVITY

**Pretty soon
you may be making
your own electricity
from natural gas.**

Every light in the house and more than a dozen appliances operating at the same time... *most* of the time.

How'd you like to pay this electric bill?

A few years from now you just might not mind at all. Because you might not have an "electric bill". You, and the owner of this home, may be able to produce all the electricity you need with a "fuel cell" powered by natural gas. The same natural gas that saves you so much money on heating, cooling and cooking today.

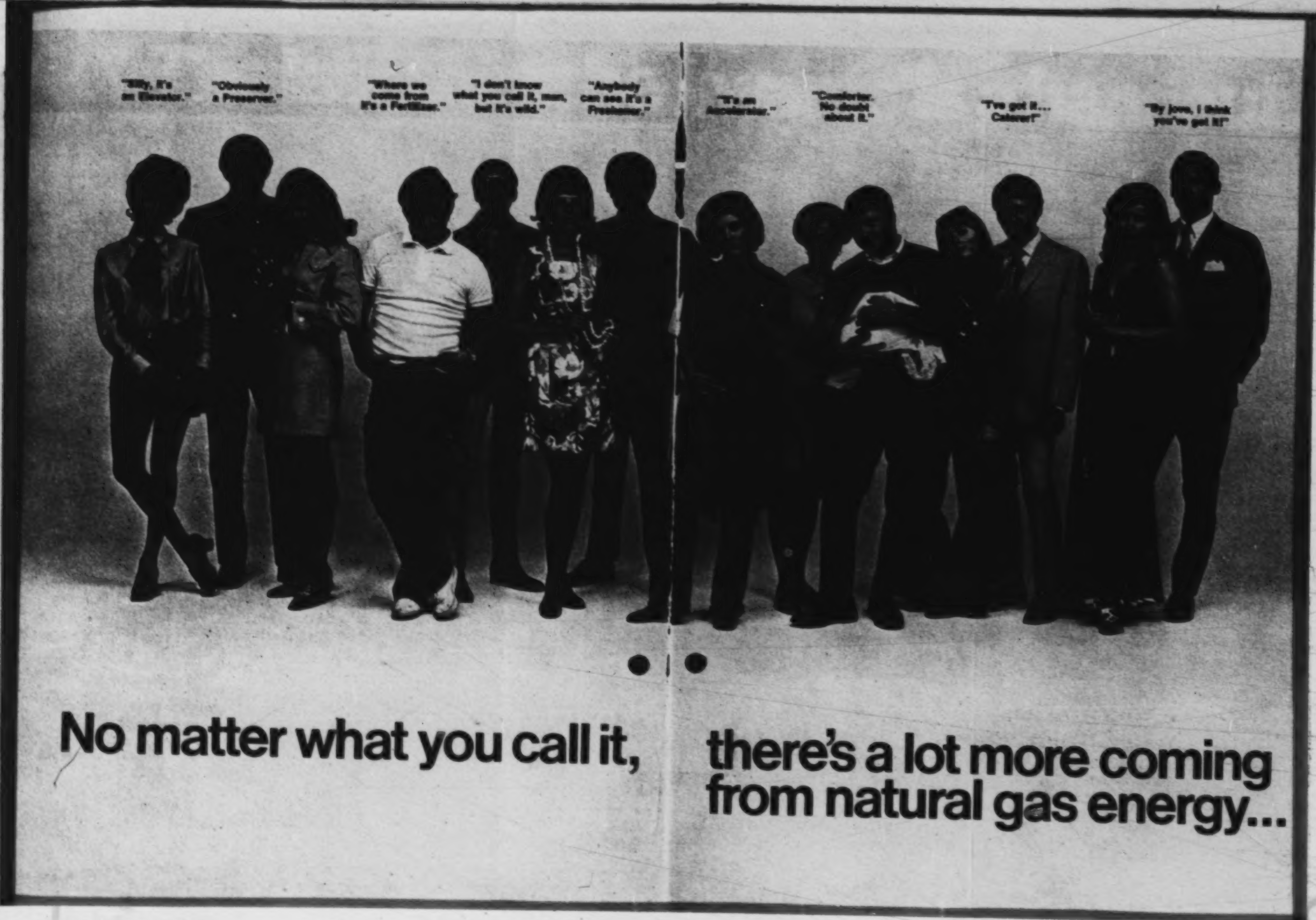
The gas fuel cell makes electricity chemically. Natural gas is piped in. It takes a safe chemical bath... and comes out electricity! Enough electricity for lights, TV, stereo, kitchen appliances, power tools and all the little labor-saving, luxury-living gadgets that are here today or on their way.

When can you order yours? Not just yet... but maybe sooner than you think. We have a working model of the gas fuel cell now. And yours could be ready before long. If you have natural gas, you're all set. For you, we're going to make electricity as economical and dependable as natural gas.

There's a lot more coming from natural gas energy.

Northern Illinois Gas Company

DEFENDANT'S
EXHIBIT
201


"Silly, it's an Elevator."
"Obviously a Preserver."
"Where we come from it's a Fertilizer."
"I don't know what you call it, man, but it's wild."
"Anybody can see it's a Freshener."
"It's an Accelerator."
"Comforter. No doubt about it."
"I've got it... Caterer!"
"By jove, I think you've got it!"
No matter what you call it,
there's a lot more coming from natural gas energy...

1186

DEFENDANT'S EXHIBIT 202

Another shopping center finds that making it's own electricity is the best buy.

Waukesha Gas Energy Systems produce electricity for lighting, heating and cooling.

Building a big shopping center can easily give you some big headaches. Especially when you begin thinking of utility costs for lighting, heating and cooling.

That's why the owners of Turfland Mall in Lexington, Kentucky, chose a Waukesha Gas Total Energy system.

How does a Gas Total Energy System work? Gas-fired Waukesha Enginators** provide all of the electricity the shopping center needs. In the process, huge amounts of engine heat are produced. But this heat doesn't go to waste. Because in a Gas Total Energy system it's recovered and used. For heating, cooling, and hot water. *Waukesha's factory-tested family of engine-generators.

This thermal efficiency is the reason a Gas Total Energy system is so economical. In fact, installations of this kind can be more than twice as efficient as today's best steam electric generating stations.

And with a Waukesha Gas Total Energy system, area power failures are not a problem. Because all the power is dependably produced on the site. Not from a distant source.

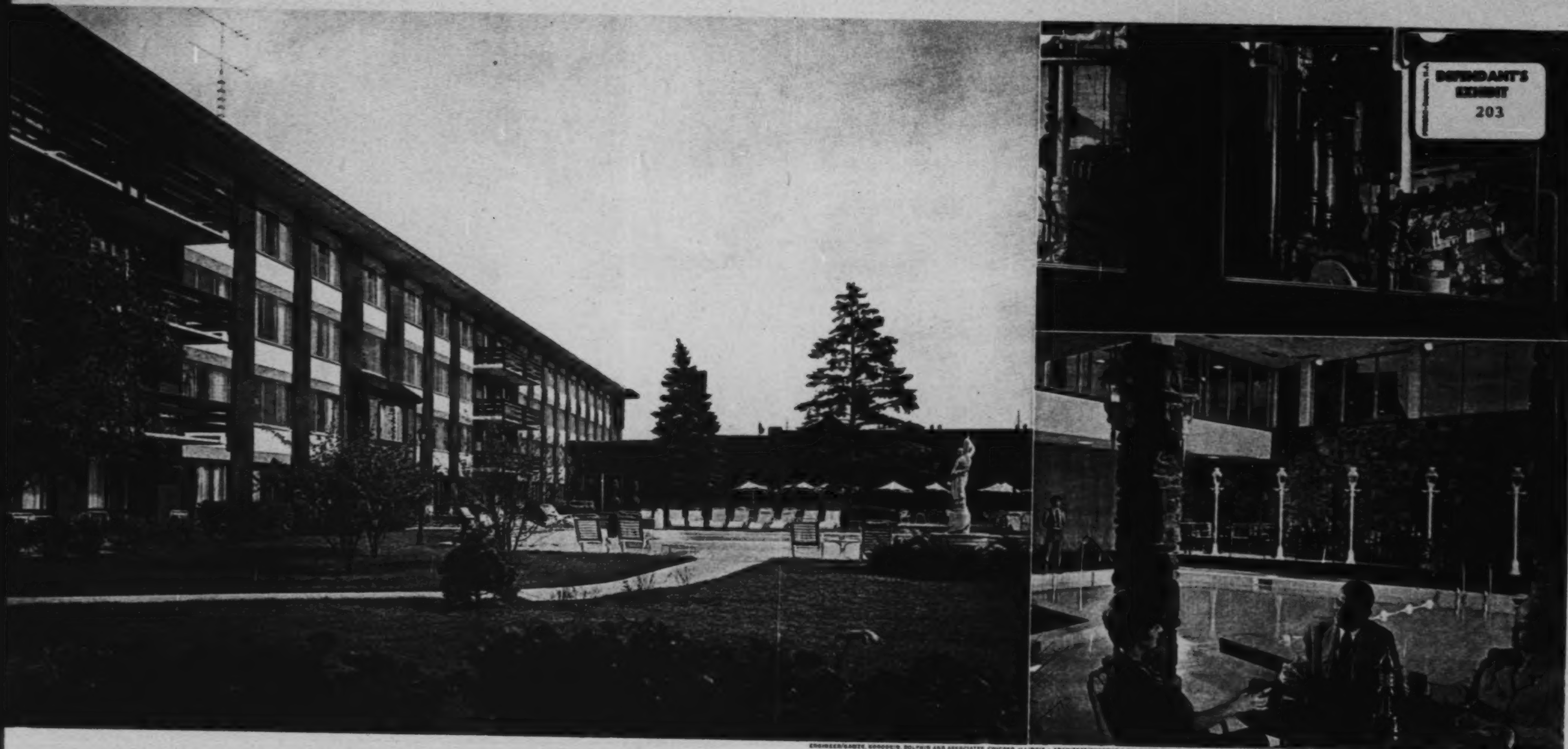
So even if the lights go out for everyone else, this shopping center and its customers are never affected.

Economical Gas Total Energy systems are working in schools, buildings, shopping centers, and plants around the country. Can it work for you? Find out from your Waukesha representative. Or the local Gas Company Sales Engineer. There's no reason why you can't get in on a good buy, too. • AMERICAN GAS ASSOCIATION, INC.

For all your energy needs, Gas makes the big difference.

AG-14951—This advertisement appears in Buildings, January; Heating, Piping and Air Conditioning, February; Architectural Record,

DEFENDANT'S EXHIBIT 203



ENGINEER/[illegible] AND ASSOCIATES, CHICAGO, ILLINOIS • ARCHITECT/[illegible] COMPANY, CHICAGO, ILLINOIS

Sheraton-O'Hare reduces utility costs over 50%.

Waukesha Gas Engines produce electricity, cooling and heating.

Suburban Chicago's Sheraton-O'Hare made a drastic cut in utility costs by going to Gas Total Energy. But economy was only one reason why this major hotel stopped buying electricity. The memory was still vivid of the 72-hour electrical service break caused by a 1965 ice storm. So they also wanted the dependability and security of a Total Energy System.

Four Waukesha Gas-fuel engines are at the heart of the system. The Waukesha engines drive electrical generators. Two of them handle the daily utility load. Two others stand by for emergency and for future expansion. (Including a planned convention center.)

What makes a Gas *Total* Energy System? The heat of the engines is recovered and put to work for absorption cooling, heating and hot water.

This unique combination of economy, efficiency and reliability is why so many commercial buildings are choosing Gas Total Energy.

Learn more about what Gas Total Energy can mean to you. Consult with your Waukesha distributor or contact your local Gas Company Sales Engineer.

AMERICAN GAS ASSOCIATION, INC.

Gas makes the big difference.

AG-76915—This advertisement appears in Business Week, March 30, 1968.
KETCHUM, MacLEOD & GROVE, Inc.

THIS IS A PAR ACTIVITY.

DEFENDANT'S EXHIBIT 204

Shoppers buy all year 'round in an ideal climate created with Gas Total Energy.

The comfortable climate of all 62 stores and connecting malls is an important reason for the popularity of Dixie Square Shopping Center in Harvey, Illinois. Everything is under one roof, climate-conditioned with economical and reliable Gas Total Energy. And each store is equipped with a system that lets the tenant regulate the temperature.

But Gas Total Energy does more than cool and heat. In fact, it can meet just about any energy need you can think of.

At the heart of this Gas Total Energy system are six natural Gas-fueled engines. In the process of generating electricity, a considerable amount of heat is a by-product. The efficient recovery of this heat for climate control and industrial Gas processes is an important reason why Total Energy can be so economical. (Installations of this kind can be more than twice as efficient as today's best steam electric generating stations.)

Gas Total Energy could be the ideal way for you to create an ideal environment. It's the dependable, economical and clean way to total comfort 365 days a year. For more information, get in touch with your local Gas Company Sales Engineer.

AMERICAN GAS ASSOCIATION, INC.
For all your energy needs, Gas makes the big difference.

AG-7683G—This advertisement appears in Chain Store Age, July; Power, June, 1968.
KETCHUM, MACLEOD & GROVE, Inc.
THIS IS A PAR ACTIVITY

DEFENDANT'S EXHIBIT 205

School Board chooses Gas heat over electric and saves over $50,000.

(That's just on first costs. So it's just first savings.)

Architect: [illegible]
Engineer: [illegible]
Mech. Contractor: [illegible]

The School Board of Ridgewood High in West Lafayette, Ohio got Gas and electric heat bids from independent contractors.

Here's what they found: Electric came in at $2.59 per square foot for the 60,000 square foot school. The Gas bid was only $1.95. The difference adds up to a big $38,200.

Another first-cost savings came from the $15,000 that the school didn't have to spend on heavier wiring and the sophisticated controls needed with electric heat.

But the savings from Gas heat go on. Because the operating economy of Gas goes on for as long as you use it.

This school is no isolated case. There are many other studies that have proved the value of competitive bids when you want the best heating value.

So if you're looking for a heating system for a school or any other installation, take a good look at Gas heat. Just call your local Gas Company.

AMERICAN GAS ASSOCIATION, INC.

For school heating, Gas makes the big difference.

DEFENDANT'S EXHIBIT 206

This new school uses Gas Energy for heating, cooling and electric power and saves $1,000 a month.

When the architects designed Catholic Central High School in Greater Muskegon, Michigan, they chose a Gas Total Energy system. The result has been savings estimated at $6,300 on power and heat generation in just six months.

One of the big ways this system saves is in the recovery of by-product heat. Heat from the combustion engines is recovered for absorption cooling, space and water heating. This efficient use of Gas Energy helped make this one of Michigan's most economically built and operated high schools.

Consider Gas Total Energy for your new buildings. Your local Gas Company Sales Engineer can give you more information.

AMERICAN GAS ASSOCIATION, INC.

Gas makes the big difference.

AG-77451—This advertisement appears in Actual Specifying Engineer, August; Architectural Record, August; American School & University, September; Domestic Engineering, September; Nation's Schools, September; Catholic Market, September/October; Business Week, October 5; Education News, October 7; Progressive Architecture, October; U. S. News & World Report, October 7; American School Board Journal, November; College Management, November; Nation's Schools (Board Members' Edition), November; Catholic Building & Maintenance, November/December; College & University Business, December; Heating, Piping & Air Conditioning, December; School Management, December, 1968.

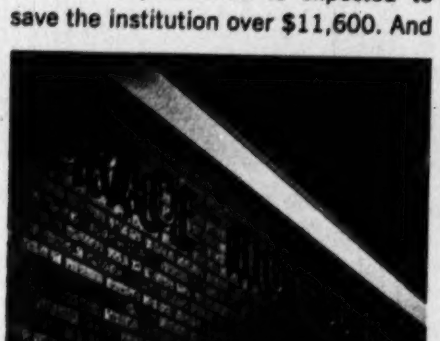
THIS IS A PAR ACTIVITY

KETCHUM, MACLEOD & GROVE, INC.

DEFENDANT'S
EXHIBIT
207

Gas produces all the energy this high school needs (including electricity) at a projected savings of $11,639 a year.*

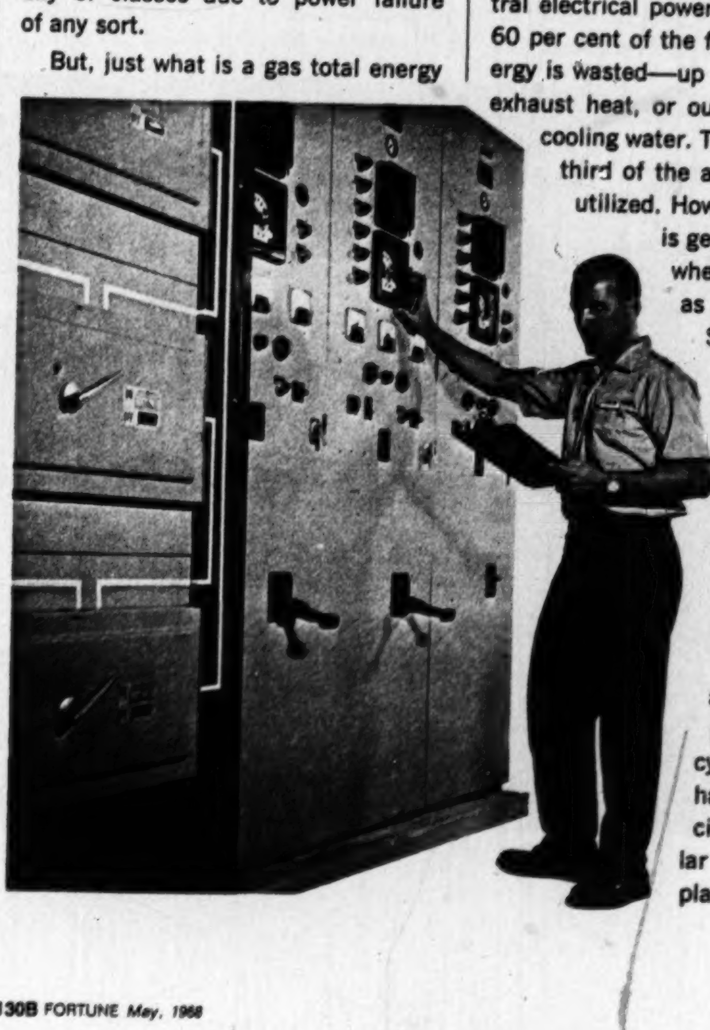
Hard to believe? It's true. In its first year of operation, the gas total energy plant in use at Grace High School in the Minneapolis area is expected to save the institution over $11,600. And



the reliability has been outstanding, too. Students haven't missed a single day of classes due to power failure of any sort.

But, just what is a gas total energy system? It's a method of power production based upon on-site generation with natural gas provided by Minneapolis Gas Company as the fuel. At the heart of Grace High School's system are three gas reciprocating engine-generator sets, any two of which can provide all of the electricity needed in the school. (Approximately 350 kilowatts per hour peak load during school hours.) Exhaust and engine-jacket water heat from the engines is captured by a 110-ton absorption unit and a heat exchanger to produce the energy used to heat and cool the 151,000 square-foot complex, as well as heat the domestic hot water.

Herein lies the economy secret of the gas total energy system. In a central electrical power plant, more than 60 per cent of the fuel's potential energy is wasted—up the stack with the exhaust heat, or out with the engine cooling water. Therefore, only one third of the available energy is utilized. However, when power is generated at the site where it is to be used, as it is at Grace High School, the energy not converted into electricity is captured to meet the operation's thermal needs: heating and cooling. Grace High School's total energy system operates at approximately 80 per cent efficiency, or two-and-one-half times the efficiency of the regular electrical power plant.



What does this increased efficiency mean to Grace High School? Simple: Money.

*Projected Purchased Power Costs, School Year, 1966-67 (Gas and Electricity)	$26,391.00
*Projected Total Energy Operating Costs, 1966-67 (Including Maintenance Overhaul Allowance)	14,752.00
Total Operating Savings, 1966-67	$11,639.00

In addition to the $11,600 in projected operating savings this year, the school realized an additional savings in that they didn't need to purchase expensive standby power equipment. Furthermore, the system also made it possible to enclose the building substantially, thereby eliminating perimeter walls and, thus, saving a considerable amount on construction costs. When asked how he felt about the gas total energy system at Grace High School, Building Maintenance Superintendent Brother Donald said the system was ". . . economical and efficient, and operates with a minimum amount of maintenance and supervision."

Gas total energy systems are currently saving money for more than 350 installations like Grace High School all across the country. One can do the same for you in your operation. For more information, just drop us a line. You'll be very glad you did.

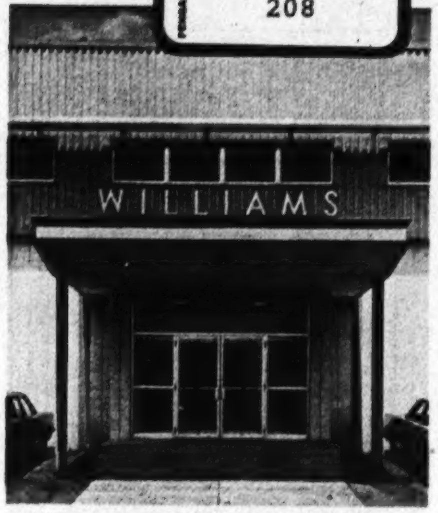
For information, current publications, or a preliminary study on the feasibility of a gas total energy system in your operation, simply write: Sales Promotion Department, Northern Natural Gas Company, 2223 Dodge Street, Omaha, Nebraska 68102. Of course you're under no obligation.

Northern Natural Gas Company
Home Office: Omaha, Nebraska

*All cost figures based upon a study by Charles J. R. McClure and Associates, consulting engineers, St. Louis, Missouri.

DEFENDANT'S EXHIBIT 208

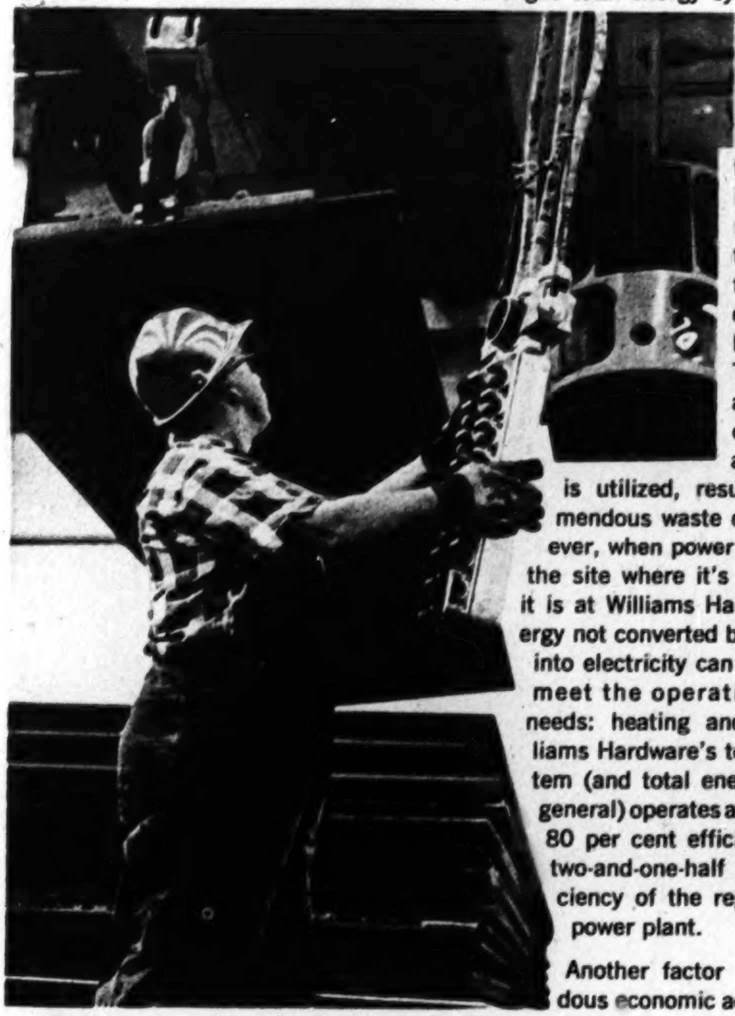
Williams Hardware buys all of its electricity from the gas company. And saves $14,000 a year in the bargain.



Impossible? Not at all. Williams Hardware, in Minneapolis, has not one, but two, gas total energy systems. (One with three engines and the other with two engines.) And in their second year of operation, they saved Williams more than $14,000 in purchased power costs, not to mention the money saved when power outages would have otherwise forced shutdowns.

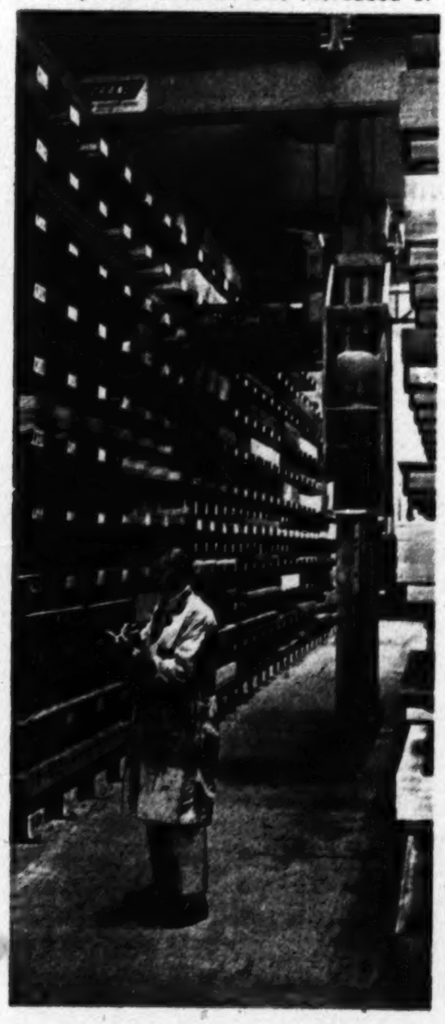
But, just what is a gas total energy system? It's a method of power production based upon on-site generation with natural gas as the fuel. At the heart of Williams Hardware's total energy systems are five gas reciprocating engine-generator sets, which supply all of the electrical power needed in the firm's offices, hardware warehouse, and massive steel warehouse combined (a total of more than 1,200,000 kilowatts a year). Then, exhaust and engine-jacket water heat from the engines is captured by a heat exchanger to produce the energy needed to cool the offices and hardware warehouse (through a 50-ton steam absorption unit), and to heat the entire 178,000 square-foot complex as well. (A completely modern complex housing not only a vast stock of sheet steel and rolled bars, but cranes, shears, press brakes, saws, flame cutting equipment, and surface grinders as well.)

Herein lies the economy secret of the gas total energy system. In a central electrical power plant, more than 60 per cent of the fuel's potential energy is lost to the atmosphere — up the stack with the exhaust or discharged as heat to water. Therefore, only about one-third of the fuel's available energy is utilized, resulting in a tremendous waste of energy. However, when power is generated at the site where it's to be used, as it is at Williams Hardware, the energy not converted by the generator into electricity can be captured to meet the operation's thermal needs: heating and cooling. Williams Hardware's total energy system (and total energy systems in general) operates at approximately 80 per cent efficiency, or about two-and-one-half times the efficiency of the regular electrical power plant.



Another factor in the tremendous economic advantage of the gas total energy system over the regular electrical power plant is the fact that a gas total energy system is by far the more reliable of the two. For instance, since Williams generates all the electrical power they need right in their own plant, power outages due to weather disturbances have been virtually eliminated. Therefore, so have work stoppages resulting from these power failures.

But, what does all this increased ef-



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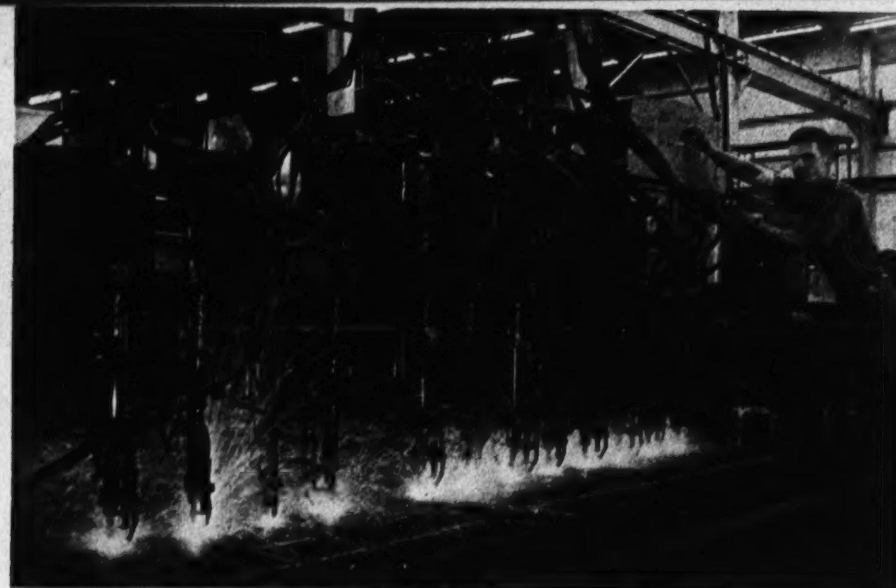


ficiency and reliability really mean to Williams? The same thing it would mean to you in your operation: Money!

Estimated Purchased Power Costs (1,200,000 kws) 5/8/67—5/8/68	$22,889.30
Purchased Gas Costs (Equiv. 1,200,000 kws.) 5/8/67—5/8/68	8,123.76
***Total Operating Savings** 5/8/67—5/8/68	$14,765.54

In addition to this $14,765.54 in operating savings over a year's time, Williams also realized an additional savings of considerable size in that they didn't need to purchase expensive standby power equipment. You see, a gas total energy system virtually acts as its own standby. But is Williams Hardware really pleased with the performance of their two gas total energy systems? Well, according to Jack Ocenasek, warehouse superintendent, they're so pleased they're currently planning the installation of their sixth gas engine later this year so they can save even more money.

Gas total energy systems are currently saving money for more than 450 installations like Williams Hardware all across the country. One can do the same for you in your operation, whatever your operation is. So, if you're really interested in cutting down your cost of doing business (And who isn't?), look into a gas total energy system today. For more information, current publications, or a preliminary feasibility study, just write: Sales Promotion Department, Northern Natural Gas Company, 2223 Dodge Street, Omaha, Nebraska 68102. Of course, you're under no obligation.

Northern Natural Gas Company

Home Office: Omaha, Nebraska

*These figures do not include maintenance costs on the total energy systems, which Williams feels are more than offset by heat-recovery savings resulting from the use of the total energy equipment.

DEFENDANT'S EXHIBIT
209

Introducing the gas guitar.

The switch to Gas Total Energy is on.

No. It's not a joke. The electricity to power the guitar, and the psychedelic lights, and the juke box, and all the other exciting effects and practical appliances in many a night club comes from a natural gas total energy system, and not from a distant power station.

Why gas total energy? Because the owners and investors who build theaters, music halls, galleries and sporting arenas know that a gas total energy system will make their buildings all but self-sustaining. And at annual operating cost savings unheard of 10 years ago.

Total energy systems powered by gas generate electricity and utilize recovered heat on the site where the energy is going to be used. This means ultra-reliable electric power for lighting, motors, appliances . . . yes, even guitars. Heat recovered from the natural gas prime movers provide energy for space heating and cooling, water heating and industrial processing. The natural gas supply, which is the sole source of energy, is also available for cooking and other applications. Total energy systems operate at maximum efficiency, need little maintenance and act as their own standby power supply.

Sold on gas total energy? If not, you soon will be. For complete details contact your local gas company, or Bob McChane, Sales Promotion Department, Northern Natural Gas Company.

Northern Natural Gas Company
Home Office: Omaha, Nebraska

Gas air conditioning is like a car that's better than good.

DEFENDANT'S EXHIBIT 210

It costs more; offers more; runs more efficiently; gives you more day-to-day satisfaction; and, in the long run, saves you a pile of money on maintenance and operating costs. Sound good? Read on:

A gas air conditioning system is what you buy when you want something very special for the long haul.

More expensive? Sure. But it pays off every time it goes on.

It's cool, it's quiet, it's dependable—no matter how hot and humid the weather.

When other units grind and grunt, a gas unit purrs. There are no major moving parts to go wrong, fewer reasons to call in a serviceman.

If a major component (chiller, coil or control) should act up anytime *within two years*, Northern Illinois Gas will send a man out to fix it free... no charge for parts and labor. You save on operating costs, too. In fact, when you compare longer life and operating savings with electric, the higher initial cost of gas air conditioning disappears.

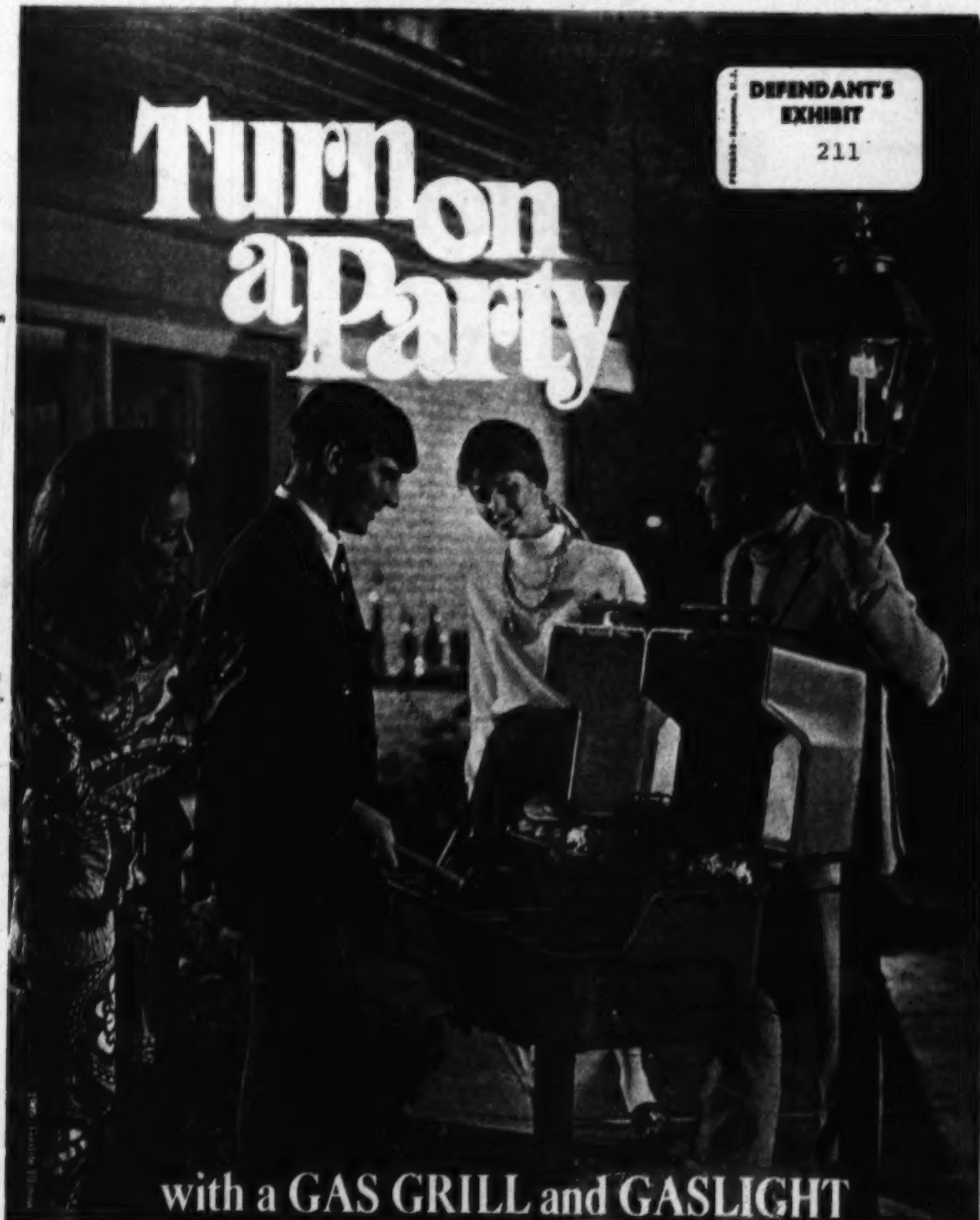
You pay nothing down and can take as much as five years to pay for your complete installation. Northern Illinois Gas can arrange the financing for you.

Interested? Get in touch with your gas air conditioning equipment contractor. Or call us.

Northern Illinois Gas Company

Serving more than a million customers

C2



We call it the Patio Pair...by Charmglow

Now it's party-time in no time at all! A modern gas grill turns on delicious charcoal taste instantly with a simple turn of the dial. Lets you cook with controlled heat . . . with even heat . . . without charcoal mess or bother.

And to put more lovely light on the party, the perfect patio companion is an elegant gaslight. Casts its soft warm light over your party with a flair that says, "you're welcome here." Yet guards your house against prowlers when the party's over.

Whether your next party be for birthdays or for entertaining...for the whole family or just for the two of you, turn it on instantly with a gas grill and companion patio gaslight.

Your family will call it a blessing. We call it the patio pair. How do you get yours? Call one of these near-by dealers now.

ALSO AVAILABLE FROM:
NORTHERN ILLINOIS GAS COMPANY
CENTRAL ILLINOIS PUBLIC SERVICE CIPS

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7221 WEST 59TH STREET / ARGO, ILLINOIS 60501

ALL GOLDBLATT STORES
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ALL SEARS ROEBUCK & CO. STORES
ALL SINCLAIR DINO FARM CENTERS
AMBOY
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ANTIOCH
Wilton's Electric Shop
ARLINGTON HEIGHTS
Hill-Behan
BELVIDERE
Johnson's App. Ctr.
BENSENVILLE
Sterling Lumber
BLOOMINGTON
Walls Heating and Cooling
BYRON
Kobel's Plumbing and Heating
CHICAGO
Alan Inc. Appliances and Furniture
Allsteel-Star Company
B.V.L. Sales and Service
Goodrich Tire and Rubber Co. Stores
Hill-Behan
Joseph Lumber
Kline's Keen Edge Service Company
Mid-City Heating Company
Mutual Pipe and Supply Company
Republic Lumber Co.
Steward Roofing and Construction
CORTLAND
Service Gas Inc.
DEERFIELD
Village Hardware, Inc.
DES PLAINES
Oakton Lawn and Garden Center
CRYSTAL LAKE
Rosenthal's Home Products Center
DIXON
Hall's LP Gas Service & Appl. Store
Schmitt Plumbing and Heating
DOWNERS GROVE
Stadtler Heating & Cooling Co.
EVERGREEN PARK
Hi-Lo Hardware
FAIRBURY
Bob Nussbaum Plumbing and Heating
NEVA
Ace Hardware
GIBSON CITY
Gibson City Plumbing and Heating
GLENVIEW
Tavi's Hardware
GRAYSLAKE
Rackenbach's Pro Hardware Store
GURNEE
Petropoulos Bros. Appliances, Inc.
HANOVER PARK
Sterling Lumber
HARVEY
Ackerman's Plumbing and Heating
HIGHLAND PARK
Douglas TV and Appliance, Inc.
Highwood Radio & Appliance Co. Inc.
Patrick Moroney Plumbing and Heating
Ravinia Hardware
Ravinia Plumbing and Heating Co., Inc.
HINSDALE
Soukup Hardware Store
HOFFMAN ESTATES
Ray's Heating and Plumbing Company
HOMEWOOD
Harold's Garden Center and Nursery
Edward Hines Lumber
Sun Ray Heating Inc.
HOOPESTON
Hoopeston Plmb. & Heating
JOLIET
Joliet Home Heating
KANKAKEE
Salzman Plumbing and Heating
LA GRANGE
Dick's Hardware and Paint
LAKE FOREST
V. J. Killian Company
LIBERTYVILLE
Galiger Heating Company
LYONS
Star Piping and Heating
Mc HENRY
R and D Heating-Cooling Company
MAYWOOD
Riley Heating and Cooling
MT. PROSPECT
Edward Hines Lumber Company
Kersting's Garden Center
MOMENCE
Town and Country Furniture and Appl.
MUNDELEIN
Mitchell Heating Company
Hill-Behan
NORTHFIELD
Boss Hardware and Sports
OAK LAWN
A Best Sales and Service
ONARGA
Onarga Heating, Cooling and Plumbing
OREGON
Johnson's Appliance
PALOS HEIGHTS
Alos Plumbing
PONTIAC
Smith Plumbing and Heating
PRINCETON
Princeton Gas Appliance
RIVER GROVE
Elm Sheet Metal
ROCHELLE
Bess Bottled Gas
ROCK FALLS
Flamegas Company of Illinois
ROCKFORD
B. F. Goodrich
Tri-State Fireplace Enterprises
ST. CHARLES
Parker Builders Supplies Inc.
R. L. Wagner and Son
SCHILLER PARK
Hill-Behan
SKOKIE
Ace Store No. 9
Northshore Refrigeration Company
Skokie Patio and Garden Center
SOUTH CHICAGO HEIGHTS
Earl's Appliance
WAUCONDA
Blackburn and Broughton, Inc.
WAUKEGAN
Ace Hardware Store
Harmony Haven TV and Appliances
Midwest Furnace Company
10th Street Hardware
United Heating Company
Wendricks-White Inc. Plumb. and Heat.
Whitten Heating Company
WESTERN SPRINGS
Village Hardware
WILMETTE/WINNETKA
Kirland Mower Service
WINNETKA
V. J. Killian Company
WORTH
Worth Hardware Inc.
YORKVILLE
Schneider Refrigeration and Appliance
ZION
Kern Heating Company

DEFENDANT'S EXHIBIT 212

Now. The gas self-cleaning oven. For builders who like to build sales. Period.

Self-cleaning gas ranges by Magic Chef.

It's the biggest, wildest, most exciting Gas Industry promotion ever. Period.

Cash in on the massive advertising attack, and build around it. Because *this* is the year of the *gas* self-cleaning oven.

Your home-building and home-remodelling prospects will be seeing it on television. And reading about it in Life and other national magazines. And being exposed to it almost everywhere appliances are sold.

This all-out promotion will announce that the gas self-cleaning range is fast, cool, and economical. It's available in slide-in, free-standing and eye-level models —30 and 36 inch widths—all colors. Remember that more of your customers prefer gas to begin with—and now that gas has a self-cleaning oven, more and more people will be joining the ranks. How about you? See your Gas Company for details.

AMERICAN GAS ASSOCIATION, INC.

The theme is:
The gas self-cleaning oven for people who like to cook. Period.

M-9005

This advertisement appears in
House & Home—May, 1969
Professional Builder—May, 1969
NAHB Journal—June, 1969
Building Supply News—June, 1969
Kitchen Business—June, 1969
American Building Supplies—June, 1969
(220094)


DEFENDANT'S EXHIBIT 213
Texas Gas invites you to the wireless house.
The wind may blow, the rains may fall, and the thermometer may have a nervous breakdown. But the wireless house hums along, quiet and calm, making its own heat and light, cool and climate as the seasons demand.
This is the house of tomorrow. No electric power lines subject it to the whims of nature. The energy comes pure and quiet from one slim buried tube of natural gas. The gas heats and cools the house.
And some of the gas is converted into a new, super-active form of natural gas called "Reformed Natural." This reformed natural gas runs all major appliances in the wireless house. It also operates a fuel cell that generates electricity.
Even though it may be some years before the experimental house is available on the market, it's just one more result of the restless gas technology that keeps our pipeline business growing steadily year after year.
And gas is only half of it. Texas Gas is a prime mover on the booming inland waterways with our American Commercial Barge Line, and our Jeffboat shipyard.
We're moving on the highways with two strong interstate trucking enterprises: Terminal Transport and Commercial Carriers.
We're also moving into the inland offshore oil and gas business, through Crestwave Offshore Services.
And we're active in oil and gas exploration and production through our Texas Gas Exploration Corporation.
The fact is, while very few people were looking, Texas Gas moved all the way up into the top 300 U.S. Corporations.
Maybe it's time you took a closer look at Texas Gas. Write to: Texas Gas Transmission Corporation, Owensboro, Ky 42301. We'll send you our Annual Report.
TXG
Texas Gas Transmission Corporation · American Commercial Barge Line Company · Jeffboat, Incorporated · Terminal Transport Company, Incorporated
Commercial Carriers, Incorporated · Bauer Dredging Company, Incorporated · Crestwave Offshore Services, Incorporated · Texas Gas Exploration Corporation

DEFENDANT'S EXHIBIT 214

Here's the story of the Gas fuel cell.

Imagine a small cabinet-size unit in your home that produces all the electricity you need.

Now you can stop imagining. Because silent, efficient Gas fuel cells have already proved themselves in thousands of hours of operation. These incredible units are actually the same in principle as the ones that have powered American spacecraft.

There's so much faith in the fuel cell that a group of Gas industry companies is investing more than $20 million in research and development. Successful research will result in moving the Gas fuel cell from prototypes to production models, and a major industry will be built.

The research investment is based on a simple fact: the most economical way to produce energy is to convert piped Gas at the point of use. And this is true for Gas heating, Gas cooling and "Gas electricity."

But is this really so surprising? After all, Gas is almost pure energy.

AMERICAN GAS ASSOCIATION, INC.

It's electrifying.

Greenwich Gas

33 Greenwich Ave. TO 9-6900

ICC PRACTITIONERS' JOURNAL
July-August 1967

NUCLEAR STEAM-GENERATION OF ELECTRICITY: ITS IMPLICATIONS FOR THE FUTURE OF COAL TRANSPORT BY RAILWAY AND WATERWAY

JOHN C. SPYCHALSKI

Few commodities can match the longevity and significance of coal's contribution to the traffic and revenues of railways and water carriers. The primeval railways—or tramways—of Elizabethan England were contrived as a means for linking land-locked coal mines with navigable waterways.[1] Many of the railways and canals constructed on both sides of the Atlantic during what could be characterized as the dawn of the modern era in transport—1800-1835—counted coal as their single most important traffic item.[2] A century later, in 1928, the first year for which American railway freight tonnages and revenues were reported by commodity groups, coal ranked second as a source of both railway carloadings and revenues. It was exceeded only by the merchandise and miscellaneous groups, which encompass a multitude of heterogeneous finished and semi-finished manufactured goods not individually reported.[3]

But, changing technology and rival fuels challenged coal's dominance as a source of energy after 1930. Oil and natural gas virtually eliminated coal in the locomotive and maritime fuel markets and reduced coal's use (measured in tons) for residential and commercial heating by approximately 85 percent between 1945 and 1965.[4] Coal sales to firms in the manufacturing and mining industries suffered declines of lesser magnitude during the same time period.[5]

These events held potentially negative consequences for the principal modes of coal transport. Nevertheless, rising sales of coal to the electric

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Dr. Spychalski is Assistant Professor of Transportation, College of Business and Public Administration, University of Maryland.

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[1] Charles E. Lee, The Evolution of Railways (London: The Railway Gazette, 1937), pp. 13-22.

[2] W. T. Jackman, The Development of Transportation in Modern England (2nd edition, revised, London: Frank Cass & Co., Ltd., 1962), Chapter VII, and E. R. Johnson and T.W. Van Metre, Principles of Railroad Transportation (New York: D. Appleton and Co., 1918), Chapter II.

[3] Railroad Transportation, A Statistical Record (Washington, D.C.: Association of American Railroads, Bureau of Railway Economics, 1965), pp. 22-23.

[4] Bituminous Coal Facts 1966 (Washington, D.C.: National Coal Association, 1966), p. 80.

[5] Ibid.

utility industry[6] and to foreign buyers together with motor transport's capture of much actual and potential railway traffic in finished and semi-finished goods preserved coal's rank as a contributor to railway carloadings and revenues. Coal presently accounts for approximately 19 percent of total carloadings and produces about 12½ percent of all railway freight revenues.[7]

The maintenance of this rank has been achieved in the face of competition from new substitutes for the rail movement of utility steam coal.[8] Water carriage—limited, of course, to transport markets served by navigable waterways—represented the only alternative for large-volume, longer-distance coal movements until 1957, when a 108-mile pipeline carrying coal in slurry form was placed in operation between a mine at Cadiz, Ohio, and a generating station in Cleveland. Its subsequent technological and economic success sparked proposals to serve other coal transport markets with slurry pipelines. The late 1950's also saw technological advances in the long-distance transmission of high-voltage electricity. These advances increased the economic feasibility of substituting the conduction of electricity produced at locations proximate to coal deposits for the long-distance haulage of coal. The railways effectively countered the slurry pipelines—and, to a lesser extent, mine-mouth generating stations—with rate reductions based on (1) lower profit margins and (2) decreases in coal movement costs achieved through such innovations as unit trains and larger-capacity rolling stock.[9]

Coal has represented about 23 percent of the total net tons of all commodities carried by inland waterway (exclusive of the Great Lakes) since 1960.[10] In absolute terms, total inland waterway coal traffic increased from 65.9 million tons in 1958 to 86 million tons in 1964. Electric utility steam coal's share of this tonnage increased from approximately 50 percent in 1958 to 58 percent in 1964.[11]

Coal traffic on the Great Lakes rose from 40.2 million tons in 1958 to 51.3 million tons in 1964, but the portion of this traffic destined for electric utilities fell from approximately 58 percent in 1958 to 40 percent in 1964.[12] Coastal shipping and motor carriage also participate in the movement of utility steam coal, but in amounts substantially below those hauled by railway and inland waterway.[13]

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[6] Coal sales to utilities rose from 27 million tons to 242.7 million tons between 1933 and 1965. Ibid.

[7] Ibid., p. 99; and Railroad Transportation, A Statistical Record, op. cit.

[8] Utility steam coal represents between 55 and 65 percent of total railway coal tonnage. More precise data are not available. Bituminous Coal Facts, op. cit., p. 96.

[9] Modern Railroads, Vol. 21, No. 2 (February, 1966), p. 80; and Bituminous Coal Facts, op. cit., p. 100.

[10] 1964 Inland Water-Borne Commerce Statistics (Washington, D.C.: The American Waterways Operators, Inc., November, 1965), p. 12.

[11] Bituminous Coal Facts, op. cit., p. 96.

[12] Ibid. Data presented for the inland waterways and Great Lakes include tonnage carried on both a for-hire and a private basis. Revenue data for coal carried by commercial water carriers are unavailable.

[13] Ibid.

The Atom Enters

Even as railway corporate strategists were drawing measurable success from their counterattack against coal slurry pipelines and high voltage long distance electricity transmission, they, together with coal-hauling water carriers, moved toward a confrontation with the spectre of nuclear steam-generation of electricity.

During the early 1960's, nuclear power's potential economic advantage appeared promising but far from realization. Coal's continued domination of the present and near-term future of steam electricity generation seemed secure. The economies of coal-fired generating technology in its most advanced stages were generally considered to be markedly superior to anything that nuclear power could muster.[14] But suddenly—more so than even some of those closely associated with the development of nuclear steam electricity generation had predicted—the atom overtook coal. Nuclear energy's share of total electricity generating capacity ordered new jumped from 10 percent in 1965 to over 50 percent in 1966.[15] This abrupt triumph resulted from various technological advances which, taken collectively, occasioned significant reductions in both the capital and operating costs of nuclear steam power plants.

An indication of the magnitude of these reductions is provided by the fact that nuclear power stations now on order or under construction are expected to produce electricity at costs ranging downward from 3.68 mills per kilowatt hour.[16] This estimation includes allocations for depreciation and interest expenses.[17] By contrast, nuclear stations placed in operation during the early 1960's produced power at cost levels ranging from 4.00 mills per kilowatt hour to 9.37 mills per kilowatt hour *exclusive* of depreciation and interest expenses.[18]

Operating costs of privately- and publicly-owned coal-fired generating stations in service in the United States during 1965 ranged from below 2.5 mills per kilowatt hour to above 5.51 mills per kilowatt hour. The operating costs of some of these plants exceeded 10 mills per kilowatt hour (see Tables 1 and 2). These cost data include labor, fuel, and maintenance expenses but exclude allowances for depreciation, interest, and administration.

Some means for comparing the capital costs of coal-fired plants with those of nuclear-fired installations can be obtained by an inspection

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14 William Webster, "The Commercial Future of Nuclear Power," Edison Electric Institute Bulletin, Vol. 34, No. 9 (October, 1966), Section I, p. 328.

15 Barron's November 7, 1966, p. 5; and The Wall Street Journal, March 15, 1967, p. 32.

16 Public Utilities Fortnightly, February 2, 1967, p. 59.

17 And thus is dependent on certain assumptions concerning estimation of the plants' useful life and the division of costs incurred during construction between capital and expense accounts.

18 Steam-Electric Plant Construction Cost and Annual Production Expenses, Eighteenth Annual Supplement, 1965, (Washington, D.C.: Federal Power Commission, 1966), pp. 157-161.

of the investment per kilowatt of installed capacity for each type of plant. Capital costs for nuclear plants presently range from about $175 per kilowatt of installed capacity for plants of 300,000 kilowatts capacity to between $120 and $110 per kilowatt of installed capacity for 1,200,000 kilowatt plants.[19] As Table 1 indicates, the capital costs of coal-fired stations appear to be less than those for nuclear plants in the 275,000-300,000 kilowatt capacity range. However, nuclear capital costs lie below those of coal for larger-sized installations.

A dramatic manifestation of nuclear energy's apparent economic triumph over coal in relatively large generating installations occurred during the summer of 1966, when the Tennessee Valley Authority ordered a 2,196,000 kilowatt capacity nuclear-fueled power station. The Authority estimated that this plant would produce electricity at a total cost of 2.39 mills per kilowatt hour, 18 percent lower than the estimated cost of a new coal-fired facility of equivalent capacity. Moreover, the Authority's nuclear station will be located virtually atop low cost steam-coal deposits.[20]

Table 1. Plant Capital Costs and Annual Production Expenses for Selected Coal-Fired Generating Stations, 1965[1]

Name of Owning Utility and Plant	Plant Capacity (kilowatts)	Plant Investment Cost per Kilowatt Hour of Installed Capacity (dollars)	Total Production Expenses (mills per kilowatt hr.)[2]	Initial Year of Plant Operation
Alabama Power Company, Greene County Plant	272,000	$126	2.67	1965
Public Service Electric and Gas Co. (New Jersey), Hudson Station	454,800	$158	3.71	1964
Tennesse Valley Authority, Widows Creek "B"	1,125,000	$117	2.32	1961
Indiana-Kentucky Electric Corp., Clifty Creek (Indiana)	1,303,600	$115	2.15	1955
Appalachian Power Co. (American Electric Power System), Kanawha River	426,000	$128	1.98	1953
Appalachian Power Co. (American Electric Power System), Philip Sporn	1,060,000	$121	2.16	1950

[1] Source: Steam-Electric Plant Construction Cost and Annual Production Expenses, Eighteenth Annual Supplement, 1965 (Washington, D. C.: Federal Power Commission 1966) p. 2, 39, 88, 126, 146.
[2] Includes maintenance, labor, and fuel and excludes depreciation, interest, and administrative overhead.

[19] Public Utilities Fortnightly, op. cit., p. 54.
[20] Tom O'Hanlon, "An Atomic Bomb in the Land of Coal," Fortune, Vol. LXXIV, No. 4 (September, 1966), p. 132.

The Outlook for Utility Steam-Coal Transport

With these events in hand, what course can be plotted for the future of utility steam-coal carriage? The Tennessee Valley Authority's decision to locate a nuclear-fueled facility proximate to steam-coal deposits [21] is a potent thrust in support of the view that nuclear power can compete successfully with coal in virtually any geographic location. Nuclear power's ability to permanently retain this advantage will depend on the future trend of its operating and capital costs vis-à-vis those of coal-fired plants, and the atom's prospects seem to be relatively more favorable.

Available evidence indicates the likelihood of a long-run downtrend in the operating costs of boiling-water and pressurized-water type reactors now in service and on order.[22] Fuel costs for these plants, presently about 1.8-2.0 mills per kilowatt hour, are expected to decline below 1.2 mills per kilowatt hour by 1980 as a result of (1) successive reductions in the costs of fabricating and reprocessing nuclear fuel; (2) reductions in the length of time required for replacement of a reactor's "spent" fuel core; and (3) the design and manufacture of more efficient fuel cores capable of being used in reactors of present vintage.[23] Even lower fuel costs appear attainable when and if one or several of a variety of more sophisticated types of reactors presently in planning and experimental stages become operationally feasible from both a technological and an economic standpoint.[24]

Nuclear power generation costs might be reduced in some geographic locations through joint-use applications. For example, a group of Southern California utilities are presently negotiating an agreement to build a nuclear desalination plant that will also produce electricity for distribution through their systems.[25]

Nuclear generating units of existent design promise marked economies of scale. For example, the Commonwealth Edison Company's Dresden No. 2 nuclear plant, ordered in 1965, is only 20 percent larger than the same firm's first atomic plant, Dresden No. 1, which began operating in 1960. Yet, Dresden No. 2 is expected to produce four times as much electricity as Dresden No. 1 is capable of producing at half the cost of

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[21] It appears that the Authority is not yet firmly convinced that nuclear power has established a permanent economic advantage over coal. The Authority has since ordered a second nuclear-powered station, but the contract for it includes a cancellation clause that can be exercised if the tide of energy cost economies should turn back toward coal. (Business Week, January 28, 1967, p. 89).

[22] An exposition of the design, construction, and operation of nuclear generating units lies beyond the purpose of this paper. For treatments of these topics, see, e.g., Public Utilities Fortnightly, February 2, 1967, op. cit.; William Webster, op. cit.; and Fortune, op. cit.

[23] Public Utilities Fortnightly, op. cit., p. 56; and William Webster, op. cit., p. 328.

[24] Ibid.; "The Next Step is the Breeder Reactor," Fortune, Vol. LXXV, No. 3 (March, 1967), pp. 121-123; and The Wall Street Journal, March 16, 1967, p. 6.

[25] The Wall Street Journal, March 10, 1967, p. 4.

Dresden No. 1.[26] Such economies will complement recent technological innovations which have greatly reduced the costs of long-distance high voltage power transmission.

Non-nuclear steam-electric power production costs per kilowatt hour fell 10.44 percent between 1956 and 1965,[27] but this decline leveled off markedly during 1966 because "(c)ost reductions related to the continuing increase in the size and efficiency of generating units and delivered fuel cost no longer dominate the cost pattern."[28]

This appraisal applies to gas- and oil-fired units as well as to coal-fired stations, but evidence exists which suggests that a separate evaluation for coal would not produce a different answer. Significant reductions in fuel costs, which comprise between 75 and 80 percent of the average coal-fired station's total annual operating costs (exclusive of depreciation and interest)[29] appear improbable. Coal's f.o.b. mine prices for sales to large-volume buyers have remained relatively stable since 1950,[30] and coal industry executives see little chance for reducing the price of their product.[31] The delivered price of coal has been lowered in recent years through coal freight rate reductions,[32] but there are signs that no margin exists for further reductions. In fact, some carriers recently increased rates on utility coal moved in trainload lots—movements for which charges had been drastically reduced relative to charges for single-car consignments during the early 1960's.[33] Coal's use-cost will also be increased by utilities' accedence to recent demands for adjustments designed to reduce the amount of air-polluting fly ash and sulfur dioxide spewed from power station smokestacks.[34]

The future course of total costs per kilowatt-hour for coal-fueled generating stations cannot be predicted in terms of meaningful quantities. However, there is no evidence of the existence of conditions capable of occasioning scale economies in coal-fired installations that approach the magnitude of those identified with nuclear plants.

The foregoing observations together with repeated upward revisions of estimated future nuclear generating capacity and the achievement of new highs in terms of the atom's share of generating capacity ordered during the closing months of 1966 and the opening months of 1967[35] suggest that further increases in the total demand for utility steam coal will be limited. Furthermore, most of the recently-ordered coal-fired

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[26] "Nuclear Plants Turn Up the Juice," Business Week, March 11, 1967, p. 65; and Fortune, Op. cit.

[27] Steam-Electric Plant Construction Cost and Annual Production Expenses, Eighteenth Annual Supplement, 1965, op. cit., p. xiv.

[28] Federal Power Commission, 1966 Annual Report, p. 45.

[29] Ibid.

[30] Ibid.

[31] O'Hanlon, op. cit., p. 133.

[32] Bituminous Coal Facts 1966, op. cit., p. 8.

[33] Burton N. Behling, A Review of Railroad Operations in 1966 (Washington, D.C.: Bureau of Railway Economics, Association of American Railroads, 1967), p. 27.

[34] "Research Goal: Solution of the Sulfur Problem," Coal Research, No. 25 (Winter, 1966), pp. 1-6.

[35] "Nuclear Plants Turn Up the Juice," op. cit.

generating stations will either be located near mine-mouths or linked to mines by slurry pipelines.[28] Thus, total demand for the (non-pipeline) transport of utility steam coal seemingly stands little if any chance of achieving further substantial growth.

Continuance of the present indicated relationship between operating and capital cost levels in nuclear and coal-fueled steam generating stations appears highly probable and would dictate that coal concede its utility steam generation market to the atom over the long run. This implies the emergence of a corresponding pattern of long-run declining demand for the transport of coal to existing coal-fired generating stations. Thus, private and public decision makers concerned with the performance of transport firms heavily dependent on utility steam coal traffic appear to be confronted by two primary considerations: (1) The rates at which existing utility steam coal transport markets will decline; and (2) The formulation and execution of policies designed to mitigate adverse effects of the loss of utility steam coal traffic.

Determinants of the Rates of Decline in Existing Utility Steam Coal Transport Markets

The future pattern of utility steam coal traffic will be determined fundamentally by the relationship between the costs of continuing to operate existing coal-fueled generating capacity and the costs of replacing it with nuclear installations. Abstracting for the moment from other influences on the replacement of coal by the atom, which will be discussed later, this means that the susceptibility to loss (in terms of time) of particular coal traffic movements will be a function of the level of operating costs of the plant to which the coal is delivered.

An assessment of such susceptibility for individual coal transport markets lies beyond the bounds of this paper. However, a suggestive indication of the susceptibility of the total utility steam coal transport market to loss through nuclear substitution can be obtained by comparing utility coal consumption data classified by power plant operating cost ranges with nuclear power plant operating cost data. Thus, a comparison of data presented in Table 2 with the previously-noted fact that nuclear power plants now on order are expected to produce power at estimated costs (including depreciation and interest) below 2.50 mills per kilowatt hour suggests that, of the total potential 1965 utility steam coal transport market, 66.6 million tons, or approximately 27 percent, could be characterized as immediately susceptible to loss, 97.1 million tons, approximately 40 percent, could be characterized as vulnerable to loss within an intermediate-term time period, and 55.5 million tons, approximately 23 percent, could be viewed as relatively immune to loss over the remaining physical lives of the plants in which it is burned.

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[28] Steam-Electric Plant Construction Cost and Annual Production Expenses, Eighteenth Annual Supplement, 1965, op. cit., p. x; and Electrical World, Vol. 167, No. 4 (January 23, 1967), pp. 67-68.

Table 2. Coal Consumption of Steam Generating Stations Classified by Level of Production Expenses, 1965[1].

Total Production Expenses (mills per kilowatt hour)[2]	Number of Plants	Tons of Coal Consumed (000)
0 - 2.50	34	55,506.67
2.51 - 3.50	102	97,120.1
3.51 - 4.50	75	38,671.9
4.51 - 5.50	53	15,703.6
5.51 and above	66	12,239.7

[1] Source: Computed by the author from data reported in Steam-Electric Plant Construction Cost and Annual Production Expenses, Eighteenth Annual Supplement—1965 (Washington, D.C.: Federal Power Commission, 1966), pp. 1-158.

[2] Excludes interest, depreciation, taxes, and certain administrative expenses.

These data, the most recent available, must be used with the caveat that they (1) are unadjusted for privately-transported coal and coal which does not require long-distance movement by virtue of its consumption in mine-mouth power stations[37] and (2) represent only 219.3 million of the total 244.9 million tons of coal burned in steam generating stations during 1965.[38] The 25.6 million ton shortfall represents (a) coal burned in plants for which either incomplete or no operating data were reported to the Federal Power Commission and (b) coal consumed in plants producing both steam and electricity for sale.[39]

The rate of growth in the demand for electricity is another determinant of the pace at which coal-fired generating stations will be phased out in favor of nuclear plants. Questions can be raised about if and when capacity for supplying reactor equipment and/or nuclear fuel will be sufficient to fulfill demands for both new generating capacity and the replacement of existing capacity. These topics cannot be probed in depth here. However, it seems conceivable that the complementary relationship between long-distance high voltage electricity transmission and the scale economies of large-capacity nuclear generating plants could permit (to some degree, at least) the simultaneous replacement of smaller-capacity coal-fired stations and the addition of new generating capacity. Also, evidence exists that any bottlenecks which might arise in the supply of nuclear generating equipment and fuel will probably be of short- to intermediate time-length rather than of long-run duration.[40]

This raises the question of whether utility regulatory authorities would permit a level of earnings on new, technologically-advanced assets sufficient to sustain continuing financial obligations on retired, eco-

[37] Most of which rank high in terms of operating efficiency.

[38] Steam-Electric Plant Construction Cost and Annual Production Expenses, Eighteenth Annual Supplement, 1965, op. cit., p. v, p. xv.

[39] Ibid.

[40] The Wall Street Journal, January 5, 1967, p. 30; and Ibid., March 15, 1967, p. 32.

nomically obsolete assets. The point at issue here is whether financial losses occasioned by economic obsolescence can and/or should be borne completely by utility common stockholders, by users of electricity, or shared on a proportional basis by these two groups.[41] If faced with the first-mentioned alternative, utility managers might be inclined to "run-out" coal-fired plants until their undepreciated balances fall very low.

One could also ask whether utility managements would retire economically obsolete but physically undepreciated coal-fired plants in the absence of financing-regulatory barriers. Some writers[42] contend that utility companies exhibit a meager propensity for making cost-cutting innovations because of (1) the relatively assured demand for electricity and (2) suggestions that commission-administered controls over utility earnings contain no provisions for rewarding those utility firms which alacritously pursue more efficient methods.[43] But, evidence exists that at least some utilities aggressively seek out ways for reducing their operating costs.[44]

Policies to Mitigate Effects of the Decline in Utility Steam Coal Traffic

Water Transport

Evidence of the movement value of inland waterway coal traffic is unavailable (see footnotes 10, 11, and 12, supra), and coal tonnage data are not reported separately for either the private and for-hire sectors of inland water carriage or the firms within each category. Nevertheless, data presented in Table 3 are sufficient to suggest that the loss of utility steam coal traffic could hold significant consequences for firms operating on certain waterways. Such losses will, however, probably tend to be concentrated over a relatively long-run time period,[45] because an inspection of the operating costs of waterside coal-fueled power stations[46] suggests that many of these plants lie in that range described previously in this paper as "relatively immune" to replacement by nuclear power before the end of their expected physical life. Thus, there appears to be little likelihood that the value of existing floating equipment dedicated to coal haulage—and for which no alternative employment

[41] This article takes no position on the problem. It is posed because policies designed to resolve it will affect the demand for utility steam coal transport service.

[42] See, e.g., Clair Wilcox, Public Policies Toward Business (Homewood, Ill.: R.D. Irwin, Inc., revised edition, 1960), pp. 771-772; and Horace M. Gray, "The Passing of the Public Utility Concept," The Journal of Land & Public Utility Economics, Vol. XVI, No. 1 (February, 1940), pp. 8-20.

[43] Wilcox, op. cit.

[44] See, e.g., "The Pathfinder for Nuclear Power," Business Week, March 11, 1967, pp. 77-78; and Hubert Kay, "We're the Most Enterprising Utility in This Country," Fortune, Vol. LXIX, No. 5 (May, 1964), pp. 138-141.

[45] Except, perhaps, for joint barge-rail movements.

[46] Steam-Electric Plant Construction Cost and Annual Production Expenses, Eighteenth Annual Supplement, 1965, op. cit., pp. 1-161.

of equivalent profitability can be found—will fall victim to nuclear power.[47]

But, this condition should not be interpreted as freeing water carrier executives of their responsibility for basing investments in new coal-hauling equipment on (1) carefully-researched estimates of the longevity of their existing utility steam coal transport markets and (2) identification of the availability of alternative uses for barges and towboats dedicated to coal haulage. Those coal-dependent carriers which desire a corporate life extending beyond the existence of their utility coal transport markets must intensify efforts to develop traffic in other commodities.

Great Lakes-borne coal is moved in part by vessels which also carry other bulk commodities. Some lake ships see only coal-hauling service, but their age is such that they can probably serve out the duration of the Great Lakes' utility steam coal transport markets without replacement. They have already been depreciated to the point where an early collapse of those markets would not result in significant capital losses.[48]

Nuclear power's influence on utility steam coal traffic should also be considered in public investment decisions concerning both the improvement of existing waterways and the construction of new navigation routes. Some navigation projects currently in planning and construction stages[49] are intended for locations where a substantial volume of coal tonnage either presently moves (see Table 3) or is expected to move. Benefits-cost analyses of these projects should therefore be carefully scrutinized in an effort to prevent investments in situations where it appears that coal tonnage will not endure in amounts and time-periods sufficient to permit the realization of benefits in excess of costs.[50]

Railway Transport

The loss of railway utility steam coal traffic will most acutely affect carriers in the Eastern and Southern Regions, where coal accounted for 32 percent and 19 percent respectively of total revenue carloadings in 1965.[51] Table 4 indicates the extent to which individual carriers in these areas depend on coal traffic. A precise breakdown of the proportion represented by utility steam coal (as distinguished from coal destined for other uses) is unavailable, but, as noted previously, utility steam

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[47] The physical life of a hopper barge of contemporary design generally ranges from 15 to 25 years.

[48] Transport Statistics in the United States for the Year Ended December 31, 1964, Part 5, Carriers by Water (Washington, D.C.: Interstate Commerce Commission, Bureau of Accounts, 1965), pp. 2-3.

[49] "List of Navigation Construction Projects and Planning Starts," American Waterways Operators Association Weekly Letter, January 28, 1967, Appendix.

[50] Political decision-making's role in navigation investment is acknowledged, but it should not prevent at least the suggestion of economically rational courses of action.

[51] Yearbook of Railroad Facts (Washington, D.C.: Association of American Railroads, 1966), p. 29. Coal accounted for 6.1 percent of total revenue carloadings in the Western District in 1965.

Table 3. Bituminous Coal and Lignite Tonnage on Selected Inland Waterways, by Total Amount and by Rank and Percentage of the Total Net Tons of All Commodities Moved, 1964.[1]

Waterway	Bituminous Coal and Lignite[2] Total net tons	Rank Relative to total net tons of all commodities moved	As a percentage of the total net tons of all commodities moved
Mississippi River	10,203,437	2	6.0
Illinois Waterway	7,878,706	1	25.6
Calument-Sag Channel	456,303	6	9.4
Ohio River	46,346,461	1	48.1
Alleghany River	2,795,145	1	57.4
Monongahela River	31,423,760	1	83.1
Kanawha River	7,580,265	1	60.5
Kentucky River	52,455	3	11.3
Green and Barren Rivers	10,353,876	1	99.9
Tennessee River	6,295,823	1	40.8
Black Warrior, Warrior and Tombigbee River System	2,162,926	1	29.2

[1] Source: Computed by the author from data presented in 1964 Inland Water-Borne Commerce Statistics (Washington, D.C.: The American Waterways Operators, Inc., 1965), pp. 7-21.
[2] Includes tonnage hauled by both private and for-hire carriers.

coal represents between 55 and 65 percent of all coal tonnage moved by the railway system as a whole. A crude indication of the value which this traffic represents can be obtained by observing that 55 to 65 percent of total railway coal revenues ranged from $182.4 million to $215.5 million, respectively, in 1963.[32]

Accurate measurements of railway coal traffic's relative profitability are virtually impossible to obtain. The Interstate Commerce Commission's Bureau of Accounts estimates that total coal traffic revenues amount to 108 percent of the out-of-pocket costs occasioned by coal movements.[33]

[32] Bituminous Coal Facts, op. cit., p. 99.

[33] Interstate Commerce Commission, Bureau of Accounts, Distribution of the Rail Revenue Contribution by Commodity Groups—1961, Statement No. 6-64, Washington, D.C., June 1964, p. 41. The bounds of this paper preclude an in-depth critique of the Commission's estimation procedures. However, it should be noted that the percentages presented here are products of gross averaging which, among other shortcomings, does not reflect the fact that rail unit costs and revenues on each type of commodity hauled differ with variations in traffic density and operating costs over specific segments of rail line. Thus, the Commission's estimates may be either higher or lower than the relationships actually realized on specific carload journeys produced by particular railway companies between given pairs of origin and destination points. The statistical representativeness of the Commission's estimates can also be questioned, because the Commission employs revenue data obtained from its one percent waybill sample.

Table 4. Bituminous Coal Revenues as a Percentage of Total Freight Revenues, and Bituminous Coal Carloadings as a Percentage of Total Carloadings, for Selected Railway Companies in the Most Recent Years of Data Availability.[1]

Railway Company	Year	Bituminous Coal Revenues as a Percentage of Total Freight Revenues	Bituminous Coal Carloadings as a Percentage of Total Carloadings
Chesapeake and Ohio	1965	47.2	46.4
Baltimore and Ohio	1965	25.4	33.3
Norfolk and Western[2]	1965	38.9	39.0
New York Central	1965	17.1	27.9
Erie-Lackawanna	1965	5.9	9.9
Southern	1963	13.8	17.2
Louisville & Nashville	1964	24.1	30.3
Illinois Central	1963	16.7	24.9
Delaware and Hudson	1965	10.0	8.3
Reading	1965	26.9	30.1
Central of New Jersey	1963	16.6	21.5
Lehigh Valley	1963	4.7	8.3
Boston and Maine	1963	5.5	4.6
Pennsylvania	1963	16.0	21.6
Chicago & Eastern Illinois	1963	22.5	31.8

[1] Source: Moody's Transportation Manual, 1966.

[2] Includes results for Wabash Railroad; Pittsburgh & West Virginia Railway, Wheeling and Lake Erie Railway, and the former New York, Chicago and St. Louis Railroad. The operations of these companies were combined with those of the Norfolk and Western by either lease or merger on October 16, 1964.

Several of the coal-dependent roads named in Table 4 enjoy strong (for the railway industry) rates of return, while the financial stamina of others can be characterized as modest during relatively high levels of general economic activity and precarious during recessional periods. However, some of the relatively strong roads are among those most dependent on coal traffic and revenues and should therefore not necessarily be viewed as the companies most likely to emerge from a permanent decline in coal traffic with their relative strength intact.

It should also be noted that most of the coal-fueled generating stations described previously in this paper as "most susceptible to nuclear conversion" or "susceptible within an intermediate time period" are rail-served.[84]

The foregoing observations emphasize the need for early recognition of, and action to cope with, the threat which nuclear power poses to coal traffic's future. Railway companies must intensify their efforts in the areas of market research, equipment design, and cost-pricing-profit

[84] Based on an inspection of information presented in Steam-Electric Plant Construction Cost and Annual Production Expenses, Eighteenth Annual Supplement, 1965, op. cit.

analysis to (1) identify potential new traffic in non-coal commodities and (2) define and provide the service-price combinations required to profitably realize that traffic. The achievement of needed cost-price and service-quality levels may, in some cases, require radical departures from conventional operating patterns.[88] Such departures would require aquiescence to work-rule changes by labor organizations representing railway operating employees.

Railway investments in new coal-hauling assets—which continue to be made in substantial amounts at the present time[84]—must be based on rigorous analyses of the specific coal transport markets which they are intended to serve in order to minimize the probability of losses.

Those acquainted with railway traffic flow patterns will recognize that certain segments of line-haul and terminal capacity presently serving utility steam-coal movements cannot be absorbed by other traffic and will therefore have to be withdrawn from service following utility steam-coal traffic's demise. This condition together with the fact that considerable redundancy already exists in portions of the railway plant makes it imperative that barriers to the rationalization of excess capacity be removed if the financial debilitation resulting from utility steam-coal traffic losses is to be minimized. Thus, public and corporate policies that inhibit the consummation of railway mergers designed to eliminate duplicate plant and equipment must be reversed.

Conclusion

Nuclear power will abruptly terminate demand for the transport of utility steam-coal. In fact, such demand will probably rise somewhat in the immediate future. But, it will decline to the point of extinction in the long run if nuclear power maintains its economic advantage over coal-fueled electricity generation. Thus, those responsible for policy-making in carrier board rooms, government chambers, and union lodges should begin now to formulate and execute plans that will permit an orderly transition to dependence on other traffics.

[88] See, e.g., "Reading Makes a Bee-Line for Profits," Railway Age, Vol. 162, No. 4 (January 30, 1967), p. 42.

[84] See, e.g., Nancy Okulanis and Kathleen Ineman, "Railroad Improvements: As 1967 Rolls in," Modern Railroads, Vol. 22, No. 1 (January, 1967), pp. 100-197.

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DEFENDANT'S EXHIBIT 216

THE PETROLEUM SITUATION

FOR RELEASE: OCTOBER 27, 1969

IN SEPTEMBER, 1969

DEMAND

The first three quarters of 1969 have already passed into the record book. It may, accordingly, be useful to look back for a moment and consider how the year has developed. The various measures of fiscal and monetary restraint that were supposed to slow down the rate of economic growth may be starting to take effect at last, but there is little evidence that they produced the desired results earlier in the year. Gross National Product grew at the rate of 7.5 percent a year during the first three quarters of 1969 – a faster rate of growth than had been anticipated a year earlier.

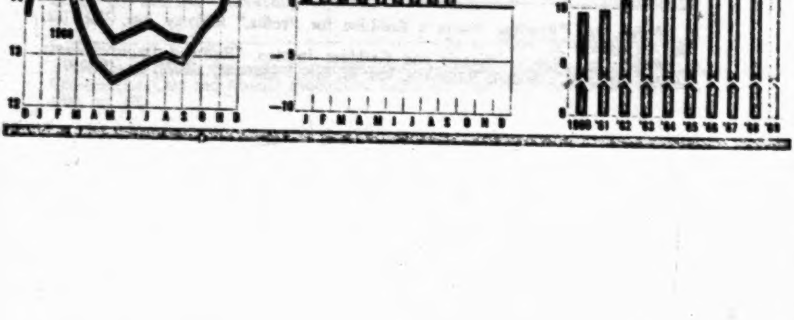
Reflecting the tempo of the economy, the demand for petroleum products also grew faster than expected during the January-September period. The growth amounted to 4½ percent, and this is likely to be sustained over the balance of the year. Not all of the products performed equally well, of course. The middle distillates tended to fall short of earlier expectations, but this was more than offset by the strong demand for gasoline and residual fuel.

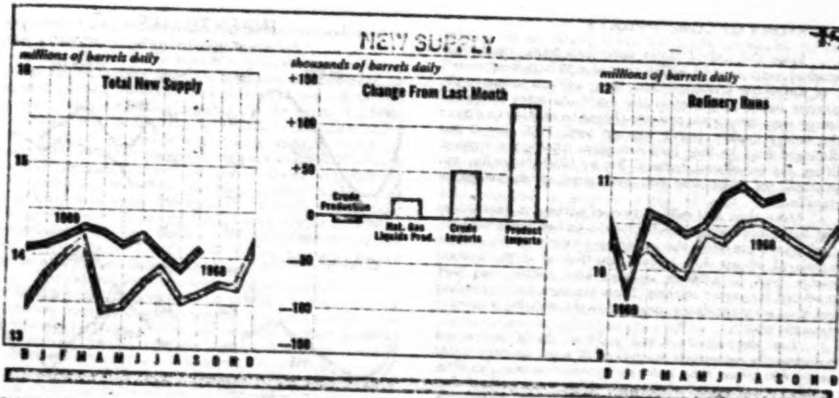
The extent to which automotive gasoline demand is dependent upon general business activity is not always fully appreciated. But it should be remembered that trucks and buses account for about one quarter of the total demand and of the amount consumed by passenger cars, 40 percent represents travel to and from work. Accordingly, given the strong economic growth that the nation has experienced this year, it is not surprising that the demand for automotive gasoline during the first three quarters of 1969 registered a 4.8 percent increase over the year earlier period. Demand for aviation gasoline is still dropping, but since this represents less than 2 percent of the total use of gasoline its influence is negligible.

At the outset of the year, very little growth seemed in prospect for residual fuel oil. And yet, by September, the year to date growth for this product amounted to about 5 percent. The particular area of strength is the Electric Utility market on the East Coast, where a combination of circumstances have worked to the advantage of oil. Air pollution regulations have raised serious problems for coal – the dominant fuel in the Electric Utility market. And an ample supply of low sulphur residual fuel at a competitive price has enabled oil to take full advantage of the situation.

Preliminary figures for the month of September show a 3.5 percent rise in demand for all oils over the level a year ago. Gasoline was the star performer. Demand for this product increased by 7.5 percent and, in fact, accounted for more than four fifths of the total rise in petroleum product demand. The fuel oils fared less well. Distillate lagged behind the year earlier level of demand, and residual fuel showed little change.

DEMAND





SUPPLY

Crude oil production in the United States satisfies two-thirds of the nation's demand for oil. It might be expected, therefore, that crude oil output would grow in line with demand. During the first nine months of 1969, however, there was virtually no change in this source of supply relative to the year earlier period. Alaska and Louisiana posted gains in crude oil production which were largely offset by lower production elsewhere in the nation. Texas, which accounts for a third of the nation's output, produced no more oil in the first three quarters of 1969 than it did in the same period a year earlier.

The other source of domestic raw materials – natural gas liquids – averaged 1.6 million barrels daily and registered a 5.4 percent increase during the first nine months of 1969. Thus, domestic sources provided almost four-fifths of the total new supply of oil during the year to date.

Imports of foreign crude oil during the first three quarters of the year averaged 1.4 million barrels a day, 13.5 percent more than in the same period last year. Half of the increase, however, is accounted for by higher imports of Canadian crude.

In 1968, crude oil shipments from Canada into the area East of the Rockies averaged 300 thousand barrels daily. For 1969, an import ceiling of 306 thousand barrels daily was established by the Department of the Interior and the Canadian government. Because Canadian imports exceeded this limit by almost 40 thousand barrels daily between January and May, the Administration again conferred with Canadian officials and a new understanding was reached stipulating that imports would not exceed the original 306 thousand barrel a day limit from May to the end of this year. Since May, however, Canadian crude imports have averaged 334 thousand barrels a day and in September they reached 385 thousand a day. On the West Coast, Canadian crude imports rose from 164 thousand barrels daily in the first nine months of 1968 to 210 thousand a day this year.

Imports licensed directly by the government are running ahead of the quota established for 1969, but this will have to be corrected during the fourth quarter.

In September, there was a small increase in the domestic production of crude oil and natural gas liquids. A 17 thousand barrel a day increase in Louisiana indicated the beginning of recovery following the over 100 thousand barrel a day curtailment of crude production which resulted from hurricane Camille. Alaskan crude output reached a record 219 thousand barrels a day – 21 percent above the year earlier level and 11 percent above the prior month's production.

INVENTORIES

Stocks of all oils at the end of September amounted to 1,034 million barrels, only a million barrels higher than a year ago. Individual product inventories appear to be in good shape. Distillate fuel oil stocks are somewhat below the record high level which was reached in September last year, but they are more than 10 million barrels higher than in any previous year. Residual fuel oil stocks, too, have dropped back from last year's record level.

The inventory build-up in September was on the heavy side – 28 million barrels were added to refined product storage. Crude oil stocks, on the other hand, were drawn down by 5 million barrels, resulting in an over-all inventory accumulation of 23 million barrels for the month.

PRICE

On the West Coast, wholesale prices of both premium and regular grade gasoline dropped a half cent a gallon in September. They are now at their lowest level for this month in the past two years. Mid-Continent premium and regular grade gasoline closed September with ½ cent recovery, after having suffered a full cent decline in August. Compared with a year ago, however, gasoline was still down ½ cent a gallon, and was as much as ¾ cent a gallon below the level of two years ago.

Distillate wholesale prices increased ⅛ cent in the Mid-Continent area to 9.5 cents per gallon – ½ cent above the year earlier level. Chicago wholesale prices for heating oils moved .15 cents a gallon higher during the month. This restored prices to the same level as prevailed prior to the .15 cent drop of July 1.

There was substantial improvement in propane prices during September. The increases amounted to three-quarters of a cent a gallon in New York harbor and a full cent a gallon in the Mid-Continent. Propane prices in both these markets are now above year earlier levels but they still have a long way to go before they can be considered normal.

October 27, 1969

John D. Emerson
Energy Economics Division

THE STORY OF COAL – PART I

Since the United States came into being, nearly two hundred years ago, 40 billion tons of coal have been mined. Coal fueled our transition from an agricultural nation to the greatest industrial power in the world. As other sources of energy were developed, coal was obliged to surrender a part of the energy market, but it was not until 1950 that it was dislodged from its long held first place. During the nineteen fifties, the use of coal declined. But by 1960 the decline was arrested, and since that year coal consumption has grown steadily.

More than 500 million tons of anthracite, bituminous and lignite coals were consumed in the United States last year. Coal mines provided the energy equivalent of 6½ million barrels of oil per day, or fully one-fifth of all the primary energy used. In addition, another fifty million tons were produced for export markets. These tonnages are huge indeed but they are insignificant compared to the available reserves of domestic coal.

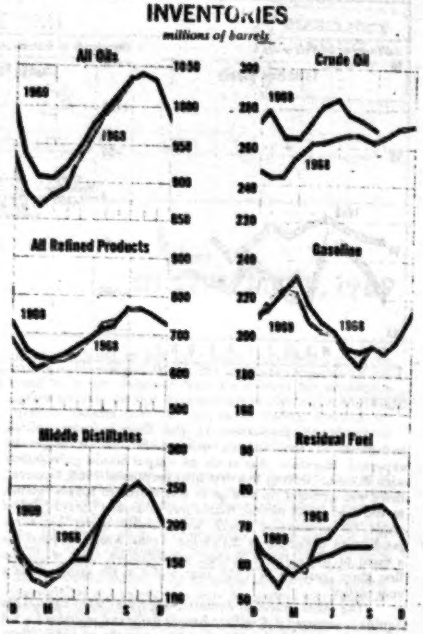
Coal deposits are found in 34 of the 50 states, and economically recoverable reserves of all types are estimated at nearly 800 billion tons. Last year's production rate, therefore, could be maintained for nearly fifteen centuries before existing domestic resources were exhausted. These raw figures, however, tell only part of the story. Bituminous coal reserves will not satisfy needs for anthracite coal, nor is it feasible to fuel utility boilers on the East Coast from coal fields in Colorado. Quality and other economic considerations also trim the real marketability of some deposits, but even so there is positively no question about the adequacy of our national coal supply.

Although reserves are found in many parts of the United States, more than 90 percent of domestic consumption occurs in the North Central and East Coast regions of the country. These areas include the principal coal producing states – Pennsylvania, West Virginia and Virginia in the east, and Kentucky, Illinois, Ohio and Indiana in the central region. The freight element represents such a large proportion of the delivered cost of coal – as much as 40 percent in many cases – that major markets have developed only within a limited distance from production centers. Currently, large new mines are being opened in some of our western states to fuel electric power stations. But, basically, the future for coal continues to lie east of the Mississippi.

There are hundreds of varied uses for coal, oil, natural gas and other fuels. For convenience, they can be grouped into four major markets for primary energy: Industrial-Commercial, Transportation, Electric Utilities, and Residential. The Industrial-Commercial market is by far the largest and accounts for 38 percent of over-all primary energy consumption. It comprises the needs of many diverse forms of economic activity. Among them are heat for large buildings, fuel for industrial processing and such non-energy uses as paving materials and chemical feedstocks.

Second in size are the energy requirements of all forms of land, air and water transportation. They currently represent a quarter of the total. In third place with 22 percent of the market, and growing fastest, are the needs of Electric Utilities for generation purposes. Accounting for 15 percent, the Residential market is the smallest of the four categories. This market includes various uses for energy, but home heating is the primary one.

Coal is consumed in all four energy markets but its volume varies both by market and by region. In the transportation category, for example, coal has been practically eliminated due to changing technology. The railroads began to convert from coal to more efficient oil-burning locomotives in the late thirties. This change was delayed because of other defense requirements during World War II, but the conversion program was resumed in the post-war period. In 1950, nevertheless, almost three-quarters of all locomotives in the country still burned coal and sixty million tons a year were mined for this purpose. As more and more diesel locomotives were brought



into service, this substantial outlet for coal disappeared in a few short years. The coal used for railroad fuel today is burned primarily in the mining regions, and the volume is so small that it is no longer significant. The other transportation usage for coal – fuel for ships – has also been eroded by technological advances. Older vessels, primarily those active in the Great Lakes trade, still consume almost half a million tons of coal annually. But all new ships are powered by diesel or residual fuel oil. As the older coal-burning vessels are gradually retired, therefore, this market will dwindle away, too.

The coal industry has had a similar painful experience in the Residential energy market over the past twenty years. Consumption trends have tended to follow those in the Transportation sector, although the slide has been less pronounced. After World War II, homeowners were attracted toward oil and natural gas for heating purposes. These fuels were slightly more costly but offered excellent burning characteristics and, more importantly, eliminated the unpleasant dust, storage and ash handling problems associated with coal furnaces. This convenience factor coupled with effective marketing techniques by the petroleum industry led to coal's decline.

As recently as 1950, coal was still the dominant fuel for home heating. It served the needs of nearly half the market. But in subsequent years, coal lost this position and currently it provides less than 6 percent of the primary energy used in the Residential market. Natural gas, with a 52 percent share, is the market leader now. Most of the remaining homes heated by coal are located close to the Appalachian and Mid-Western mining regions, and they burn less than twenty million tons per year, or 4 percent of total coal consumption. Many of these homes may be converted to other fuels during the seventies. By 1980, therefore, residential coal consumption is

expected to drop to about half the current level and represent only a very minor share of the over-all market.

The Electric Utility market is by far the most important outlet for coal among the major categories. It accounts for 60 percent of total domestic sales at present and will become proportionally even more important in the future. Last year more than half the electrical power used in the United States was produced in coal-fired generating stations. In certain geographic areas the proportion was even higher. The North Central region, for example, used coal to meet four-fifths of the electric utilities needs. Another important market is the East Coast area where coal accounts for nearly two-thirds of the generation of electricity. Energy consumption by utilities constitutes a very large market, so enormous volumes of coal are involved. In 1968, almost 300 million tons were burned under utility boilers throughout the nation.

The outlook for increased coal consumption by electric utilities is bright. But inter-fuel competition is intense and air pollution restrictions against sulphur or other emissions pose substantial problems for the coal industry in many areas. In the burning process all fuels – coal, oil and gas – release sulphur and other pollutants in varying degrees. Coal, however, has the greatest difficulties in this respect. The industry must hold down the delivered cost of coal and at the same time devise methods to meet more stringent and widespread air pollution regulations if it is to realize in full the opportunities for increased sales to utilities.

Although the Industrial-Commercial market for primary energy is the largest of the four major categories, it ranks only second in importance for coal. Until 1955, coal reigned as the dominant energy source in this market. But in the following years, it was displaced by natural gas, which had become available in substantial quantities and at very low prices. Oil also offered vigorous competition in the Industrial-Commercial market. To an extent, it too was partly responsible for the decline in coal demand.

The Industrial-Commercial market, however, remains an important outlet for coal even though its market share is falling. In 1968, more than 190 million tons, or two-fifths of total coal sales, were made to these customers. Roughly half of this volume was used by the steel industry to produce the coke needed in the steel making process. Growth in the sales of coking coals, however, has tended to be very slow because of progress made by the steel industry in reducing the volume of coke required to produce a ton of steel. Technological improvements have reduced this quantity by fully a third since 1950. During the same period, the use of anthracite and bituminous coal by general industry declined by more than twenty million tons. The drop primarily reflects competition from alternative sources of energy. But it was also the result of mounting public demand for cleaner air. The coal industry has not yet succeeded in developing economically efficient methods to remove air pollutants given off by coal-fired industrial plants. The industry is losing coal customers today and seems likely to lose more in the future unless it can solve this difficult problem.

Coal makes a major contribution to the energy needs of the United States, so it is comforting to view the almost inexhaustible supply of domestic reserves. During the coming decade sales are expected to increase – particularly to electric utilities. In addition, a new future for coal may develop through its conversion to a cleaner, more convenient gaseous or liquid form of energy. Certainly, it will be within our national interest to attempt to utilize our wealth of natural coal resources.

Gerald D. Gunning

UNITED STATES PETROLEUM STATISTICS SUMMARIZED

Sources: U.S.B.M., A.P.I., and C.M.B.

	SEPTEMBER 1969	SEPTEMBER 1968	SEPTEMBER Change	3 MOS. ENDED SEPT. 30 1969	3 MOS. ENDED SEPT. 30 1968	3 MOS. ENDED SEPT. 30 Change	YEAR TO DATE 1969	YEAR TO DATE 1968	YEAR TO DATE Change
	Thous. Bbls. Daily		– % –	Thous. Bbls. Daily		– % –	Thous. Bbls. Daily		– % –
Demand									
Gasoline	5,732	5,333	+ 7.5	5,909	5,655	+ 4.5	5,584	5,350	+ 4.4
Kerosine	910	858	+ 6.1	888	820	+ 8.5	920	850	+ 7.9
Distillate	1,700	1,806	*	1,663	1,629	*	2,236	2,258	*
Residual	1,660	1,652	*	1,590	1,581	*	1,840	1,884	*
All Other	3,300	3,208	+ 2.9	3,303	3,234	+ 3.0	3,232	3,078	+ 5.0
Total Demand	13,302	12,858	+ 3.5	13,266	12,918	+ 2.7	14,039	13,436	+ 4.5
New Supply									
Crude Oil Production	9,200	8,934	+ 3.0	9,224	9,078	+ 1.6	9,184	9,150	+ 0.4
Natural Gas Liquids Production	1,575	1,498	+ 5.1	1,567	1,494	+ 4.9	1,583	1,502	+ 5.4
Crude Oil Imports	1,510	1,416	+ 6.6	1,454	1,429	+ 1.7	1,392	1,229	+ 13.5
Residual Fuel Imports	1,041	1,043	– 0.2	1,005	954	+ 5.3	1,203	1,164	+ 3.4
Other Products Imports	413	395	+ 4.6	410	408	+ 0.5	461	390	+ 18.2
Primary Supply	13,739	13,286	+ 3.4	13,660	13,360	+ 2.2	13,823	13,432	+ 2.9
Net Processing Gain	320	329	– 2.7	321	312	+ 2.9	314	311	+ 0.9
Total New Supply	14,059	13,615	+ 3.3	13,981	13,672	+ 2.3	14,137	13,743	+ 2.9
Crude Runs to Stills	10,843	10,412	+ 4.1	10,855	10,522	+ 3.1	10,588	10,311	+ 2.7
	– Million Bbls. –								
Stock Change in Million Bbls.	+ 22.7	+ 21.9	–	+ 57.0	+ 72.5	–	+ 34.3	+ 88.3	–
Stocks–End of Period									
Gasoline	195	195	– 0.2						
Kerosine	51	44	+ 16.9						
Distillate	200	206	– 3.0						
Residual	68	79	– 14.1						
Other Products	255	249	+ 2.6						
Total Products	768	770	– 0.5						
Crude Oil	266	263	+ 2.0						
Total–All Oils	1,034	1,033	+ 0.1						

*Percentage change not computed as 1969 and 1968 data are not comparable.

THE PETROLEUM SITUATION

R RELEASE: NOVEMBER 28, 1969

IN OCTOBER, 1969

DEMAND

With the peak season for gasoline consumption having passed, attention is now focused on the demand for distillate fuel oils. Distillate registered an increase in October in line with the long-term trend. It is probable that most of this gain was brought about by greater use of highway diesel fuel, with only a minor portion of the increase reflecting higher demand for heating oils, even though temperatures during September and October were colder than last year.

Weakness in gasoline and naphtha jet fuel limited the total demand for petroleum to a 3.7 percent gain during October. Gasoline increased only 2.9 percent following exceptional strength last month. The demand for naphtha jet fuel was 42.6 percent below last year. It was the lowest level of naphtha jet demand since February 1966.

Residual fuel oil registered an impressive gain of 7.5 percent. This increase, however, was largely a recovery from an abnormally low level of demand a year ago.

SUPPLY

Domestic production of crude oil and natural gas liquids in October averaged 120 thousand barrels a day more than in September. Crude production increased 75 thousand per day primarily because operations in Louisiana returned to normal following the hurricane in August. Despite a higher allowable factor, crude oil output in Texas was virtually unchanged from a month ago. Reflecting seasonal trends, the production of natural gas liquids rose by 45 thousand barrels a day.

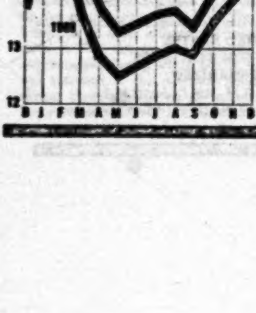
Total imports in October were slightly lower than a month ago. Residual imports increased seasonally, offsetting, to a large extent, the decline in crude oil and other refined products. Refinery runs averaged 10.7 million barrels a day during the month—a decline of 158 thousand barrels a day from last month.

INVENTORIES

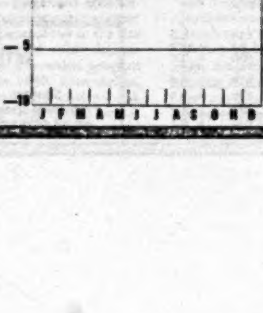
The amount of crude oil and refined products in primary storage at the end of October was within 1

DEMAND

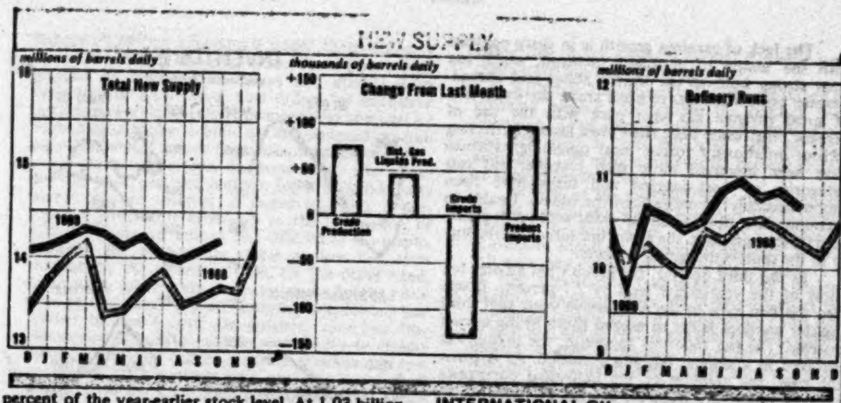
millions of barrels daily



percent change from year ago



millions of barrels daily



percent of the year-earlier stock level. At 1.03 billion barrels, the total was 9 million less than a year ago. Gasoline inventories reached 198 million barrels—only 5 million above the year-earlier level. Kerosine stocks, at 50 million barrels, were also 5 million higher than a year ago and are regarded as somewhat excessive. The excess reflects a rate of demand that has fallen below expectations. Distillate inventories, amounting to 207 million barrels, were down from the year-earlier level by 5 million. There was a larger decline for residual fuel of 11 million barrels. At 66 million barrels, however, residual stocks were in a better position relative to requirements.

PRICE

In the highly volatile Mid-Continent gasoline market, prices rose ½ cent a gallon in October. Added to last month's ¼ cent increase, the gains represented a partial recovery from the decline in August, when prices fell a full cent a gallon. Despite the increase in the Mid-Continent, gasoline prices at the end of the month were generally below the levels of recent years. The East Coast was the only major wholesale gasoline market in which posted prices were not under the levels of two years ago. In the Gulf Coast area, wholesale gasoline prices declined ¼ cent a gallon. They are now ¾ cent a gallon below their summer peak.

In contrast to gasoline prices, distillate postings in all major markets at least equalled the levels of one and two years ago. They moved up ¼ cent a gallon in Chicago but down by the same amount in the Mid-Continent. The decrease in the Mid-Continent, despite sharply lower temperatures in many Midwest states, was regarded as recognition of common discounting rather than new price softening. Kerosine prices also compared favorably with the levels of recent years, except at the Gulf Coast. In that market, kerosine was priced a full cent below a year ago. And even kerosine jet fuel was available for less than the price of regular grade kerosine last year. But in the Chicago market, kerosine prices increased ¼ cent a gallon to a level ½ cent above a year ago. The wholesale price of residual fuel advanced 5 cents a barrel on the West Coast.

G.J. Shuttlesworth

INTERNATIONAL OIL

During the first nine months of this year, demand for oil in the Free World averaged about 37 million barrels a day. This was a gain of 8 percent over the same period last year. In the U.S., demand rose by 5 percent, and in the foreign sector, requirements increased 10 percent.

Reflecting the expansion in demand, Free World crude oil production registered a 7.7 percent gain—right in line with the long-term trend. Most of the 2.4 million barrel a day growth was in the Free Foreign areas. In fact, two-thirds of this volumetric increase was concentrated in Libya, Iran, and Nigeria, each country contributing about 500 thousand barrels a day to the total gain. The Nigerian increase, of course, reflects a recovery from the effects of last year's Civil War. But Libya and Iran were the scenes of actual growth. In Libya, an all time high of almost 3.1 million barrels a day was attained during the nine month period.

The growth of oil production in other countries varied widely. Saudi Arabian production dropped slightly in the first half of 1969. But in September, it hit a record 3.2 million barrels a day with the result that output in the third quarter averaged more than 3 percent above the level reached in the same period last year. In Egypt and Indonesia, the January-September period saw very large gains—45 percent and 26 percent, respectively. But in Venezuela, production averaged 1.5 percent below the 1968 level. And in the United States, it registered a mere 0.2 percent rate of growth.

S.I. Semos

EARNINGS

In the first nine months of 1969, the combined net income of the large group of petroleum companies this Bank has under continuous survey fell slightly behind the earnings recorded in the same period last year. It was the only time since 1958 that the group has failed to achieve a growth in earnings. Because 1958 was marked by a rather severe business recession, some petroleum industry sources have been prompted by the earnings performance this year to wonder if the nation might not be experiencing another recession.

The lack of earnings growth is in sharp contrast with the tempo of petroleum demand, which has been strong both in the United States and abroad. Despite price weakness in some areas, the expansion of gross revenue has kept pace with the rise of demand. But costs have risen even faster. Reflecting various inflationary forces, most operating expenses have been increased more than revenue. But two categories of cost–interest and taxes–have risen proportionately far more than the others. Unable to accommodate all its financial needs with funds generated from operations, the group has turned increasingly to the short-term capital markets.

In the third quarter, the group's net income fell short of the year-earlier level by 2.7 percent. It was also the first time in the past twelve years that third quarter earnings failed to exceed those of the second quarter. The last time this happened, the nation was involved in a general business recession. As is often the case, the earnings of the individual companies varied substantially from the average performance of the group as a whole.

Richard C. Sparling

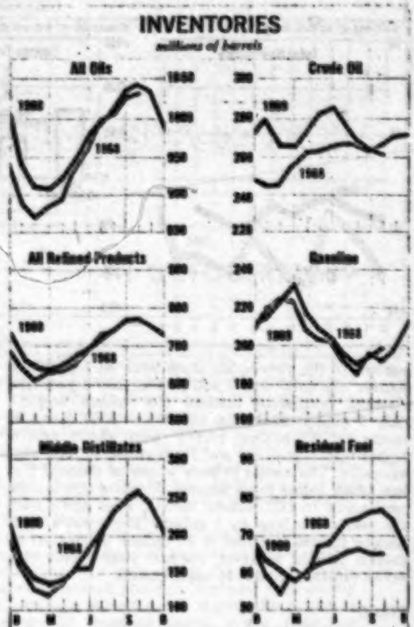
THE STORY OF COAL – PART II

The nation's requirements for primary energy in the next decade will be enormous and domestic reserves of petroleum–both oil and natural gas–are likely to be inadequate to support the potential demand. But, as was pointed out in last month's report, there is no need for concern in regard to coal. The real challenge is to devise economic methods to utilize more fully this nation's abundant coal deposits.

Consumption of solid fuels in the Transportation and Residential Markets has been declining for years and this trend is expected to continue. Although some growth is expected for coal in the Industrial-Commercial Market, gains are likely to be minor. The electric utilities, however, constitute the most important outlet for coal and will continue to do so in the future. The oil equivalent of nearly seven million barrels per day of all types of energy was used to generate electricity last year, and utility requirements will more than double by 1980. Coal is the source of more than half of this energy.

Many generating stations are designed to burn more than one form of fuel–coal, oil or natural gas–and can switch from one to another when economic considerations dictate a change. The coal industry must continue, therefore, to hold down costs and improve technology if it is to retain a competitive position. A new threat to coal's dominance–nuclear energy–will also have a significant impact in the Electric Utility Market in the years ahead.

Each major region of the United States provides a different pattern of utility fuel usage. In the Gulf Coast area, for example, most utilities use low-cost natural gas from nearby fields to generate electricity. On the West Coast, water power from hydro-electric sites provides almost sixty percent of all the energy needed. But on the East Coast, coal is the source of nearly two-thirds of the energy used for generating purposes. And in the largest regional market–the North Central area–coal represents more than three-fourths of the primary energy utilized by utilities.



In the years ahead, coal sales to utilities will be influenced by different factors in each region. On the West Coast, the limited potential for expansion of hydro-electric capacity is a factor favorable to coal. Western utilities are turning to coal deposits in Wyoming, Utah, Arizona and New Mexico to meet part of their expanding requirements. Twelve new coal-fired generating stations with a combined capacity of 4.5 million kilowatts are already under construction in these states, and others are planned. These large coal plants each consume the oil equivalent of 25,000 barrels per day. Power produced in these plants will be transmitted along extra-high voltage transmission lines for hundreds of miles to centers of consumption in the West Coast region. Currently, the coal used to generate electricity for the West Coast amounts to less than ten million tons. But, by 1980, consumption is expected to reach 70 million tons.

Another development of potential benefit to coal in the East Coast and North Central regions is the probability that domestic natural gas will be in short supply within a few years. Because utilities pay less for their energy than do other users, the natural gas that is available is likely to be channeled into more profitable markets. As a result, many electric utilities may be forced to turn, at least in part, to coal to make up the deficit.

There is another side to the coin, however. The rapid introduction of nuclear power in several areas will restrict the growth of coal markets. Electric utilities at present have only 3 million kilowatts of nuclear generating capacity in operation, but a

further 67 million kilowatts is under construction or on order. During the past year, these plants were plagued by construction delays and sharply rising capital costs. As a result, new orders for additional nuclear power stations have dropped very sharply. An expanding capacity to build nuclear powered generating plants should relieve the bottlenecks, however.

Substantial uranium discoveries have also occurred this year, and the outlook for a fully adequate supply of ore reserves is improved. This factor, together with rising efficiency in the production of kilowatt hours per unit of fuel utilized in the plants, increases the chances for stable nuclear fuel costs throughout the seventies. Coal, on the other hand, faces rising labor costs in many areas. Safety problems at the mines and air pollution regulations add further to coal's cost. On balance, therefore, the economics of nuclear power seem likely to remain favorable in many regions, and the slowdown in new orders for nuclear plants may prove to be of short duration. In the East Coast region, coal faces strong competition from residual fuel oil as well as from nuclear power. And within the past year coal has suffered some reverses. Several East Coast states north of Washington D.C., in an effort to combat air pollution, have imposed severe restrictions on the sulphur content of fuels burned by electric utilities. The petroleum industry has thus far managed to meet the new fuel standards with little change in delivered prices, but the coal industry has been less successful. The result has been a significant switch from coal to oil that has reduced utility coal consumption and, more important, weakened prospects for new coal-burning generating plants in these states. Because it is not yet practical to desulphurize coal, the coal industry must develop other means to reduce sulphur emissions from coal-fired stations—perhaps by the use of devices to remove pollutants from the stack gases. Alternatively, the industry may be able to bring large new deposits of low-sulphur coal into production. In either case, quick action is needed if similar losses in other states are to be avoided.

Although the prospects for coal are mixed in the different regions, nationwide the outlook remains favorable. Total electric utility consumption of coal was 300 million tons last year, and by 1980 an additional 120 million tons—forty percent more—will be needed for this market.

In view of the outlook for domestic supplies of oil and natural gas, serious consideration must also be given to the conversion of coal to a cleaner, more convenient liquid or gaseous energy form. Progress in this area may conceivably allow coal to regain a share of the important Transportation and Residential Markets. Renewed sales to these customers would provide greater utilization of the nation's vast reserves of coal and would reduce the nation's dependence on foreign sources of energy. Research on conversion methods has demonstrated that existing technology is adequate to do the job, but costs must be reduced further if gas or liquids produced from coal are to be competitive with the natural products.

To achieve this aim, the coal industry will have to spend substantial amounts of capital and engage in projects of enormous scale. Large commercial-size plants to produce coal liquids or pipeline quality gas are expected to cost more than $300 million each and require up to twenty million tons of coal per year. The mining part of such a venture alone, will require production two to three times greater than the output of the largest coal mine operating in the United States today.

The outloook for increased sales of coal to existing markets is good during the coming decade, despite mounting competition. And the future is potentially even more promising when the possibilities of converting coal to gas and liquids are considered.

Gerald D. Gunning

Energy Economics Division — November 28, 1969

	OCTOBER 1969	OCTOBER 1968	OCTOBER Change	3 MOS. ENDED OCT. 31 1969	3 MOS. ENDED OCT. 31 1968	3 MOS. ENDED OCT. 31 Change	YEAR TO DATE 1969	YEAR TO DATE 1968	YEAR TO DATE Change
	Thous. Bbls. Daily		– % –	Thous. Bbls. Daily		– % –	Thous. Bbls. Daily		– % –
Demand									
Gasoline	5,687	5,496	+ 2.8	5,780	5,541	+ 4.5	5,608	5,365	+ 4.5
Kerosine	972	897	+ 8.4	912	867	+ 5.2	932	864	+ 7.9
Distillate	2,116	2,014	+ 5.1*	1,829	1,806	+ 1.3*	2,315	2,233	+ 3.7*
Residual	1,810	1,683	+ 7.5*	1,725	1,605	+ 7.5*	1,984	1,894	+ 4.8*
All Other	2,415	2,381	+ 1.0	2,404	2,293	+ 3.4	3,250	2,112	+ 4.8
Total Demand	13,970	13,471	+ 3.7	13,670	13,112	+ 4.3	14,080	13,438	+ 4.7
New Supply									
Crude Oil Production	9,278	8,917	+ 4.0	9,177	8,994	+ 2.0	9,177	9,127	+ 0.5
Natural Gas Liquids Production	1,620	1,514	+ 7.0	1,581	1,490	+ 6.1	1,589	1,503	+ 5.7
Crude Oil Imports	1,384	1,481	– 6.5	1,448	1,431	+ 1.2	1,391	1,252	+ 11.1
Residual Fuel Imports	1,200	1,051	+ 14.2	1,115	976	+ 14.0	1,220	1,152	+ 5.9
Other Products Imports	356	402	– 11.4	420	387	+ 8.5	460	391	+ 17.6
Primary Supply	13,838	13,365	+ 3.5	13,751	13,280	+ 3.5	13,837	13,425	+ 3.1
Net Processing Gain	340	348	– 2.3	324	325	– 0.3	317	315	+ 0.6
Total New Supply	14,178	13,713	+ 3.4	14,075	13,614	+ 3.4	14,154	13,740	+ 3.0
Crude Runs to Stills	10,685	10,306	+ 3.7	10,775	10,436	+ 3.2	10,600	10,311	+ 2.8
	– Million Bbls. –								
Stock Change in Million Bbls.	+ 8.4	+ 9.1	–	+ 37.8	+ 80.6	–	+ 38.2	+ 67.4	–
Stocks—End of Period									
Gasoline	198	193	+ 2.8						
Kerosine	50	45	+ 12.1						
Distillate	207	212	– 2.3						
Residual	65	77	– 14.9						
Other Products	251	248	+ 1.0						
Total Products	772	776	– 0.5						
Crude Oil	261	266	– 1.9						
Total—All Oils	1,033	1,041	– 0.8						

UNITED STATES PETROLEUM STATISTICS SUMMARIZED

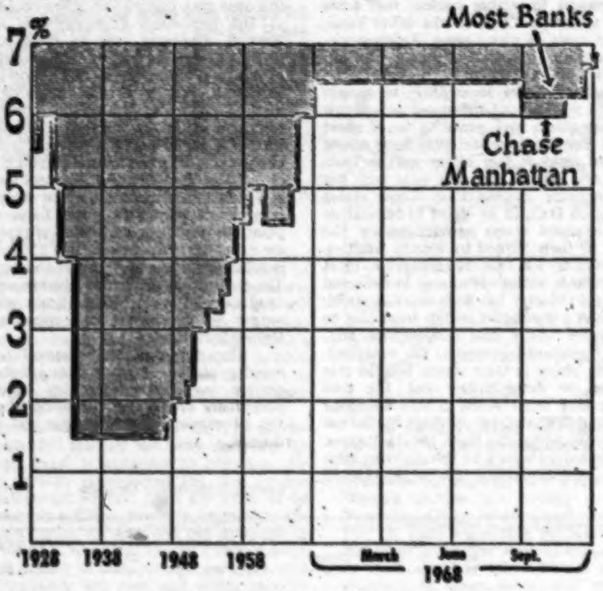
Sources: U.S.B.M., A.P.I., and C.M.B.

*Demand in 1969 and 1968 not strictly comparable.

DEFENDANT'S EXHIBIT 218

PRIME INTEREST RATE

1928 - 1968



Source: Chicago Daily News (Business and Finance Section), Page 49, December 18, 1968

DEFENDANT'S EXHIBIT 219

ELECTRIC ENERGY, INC.
POST OFFICE BOX 165
JOPPA, ILLINOIS 62953

March 9, 1970

Mr. Reuben L. Hedlund
Kirkland, Ellis, Hodson, Chaffetz & Masters
Prudential Plaza
Chicago, Illinois 60601

Re: United States v. General Dynamics Corporation, et al., Civil Action No. 67 C 1632 (N.D. Ill.)

Dear Mr. Hedlund:

This letter will confirm the substance of our telephone conversation of many months ago, at which time we discussed my letter dated November 14, 1966 to the Department of Justice in response to their letter concerning the above litigation.

In that letter, you will recall, we cautioned the Department of Justice not to infer from our letter that Electric Energy, Inc. considered the acquisition of the United Electric Coal Companies by General Dynamics Corporation to be in the category of mergers which might lead to a narrowing of the "spot" market for us and tend to increase our fuel costs. When you inquired further in our initial phone conference, I advised you that Electric Energy, Inc. did not think that the United Electric-Freeman merger would have any impact on our "spot" market and did not think that it would in any way adversely affect the competition for our business. As I pointed out to you at that time, the location of Electric Energy, Inc.'s generating station on the Ohio River is such that coal produced in the Belleville freight rate district where United Electric's Fidelity mine is located could not be shipped to us at that time on a competitive basis with coal produced in the Southern Illinois and West Kentucky districts. This was true at that time regardless of whether the coal had been offered on a contract or spot basis. Because of the freight rate disadvantage, Belleville producers are not able to compete at this time for our business unless we were to be given the advantage of a unit train movement rate, not presently existing.

In my letter to the Department of Justice I was attempting to point out to them that Electric Energy, Inc. would be concerned about mergers between producers located in the Southern Illinois and West Kentucky freight rate districts - areas from which we secure our coal.

In view of your indication to me last week that my letter of November 14, 1966 is being introduced into evidence in the law suit, I am happy to write this letter to make our position perfectly clear in this regard.

Yours very truly,

V. H. Clark
Secretary-Treasurer

VHC/sj

DEFENDANT'S EXHIBIT 220

June 29, 1942

Mr. B. L. Slack
Box 1934
Tuscon, Arizona

Dear Sir:

We are not interested in operating any coal mines except strip coal mines. For our purposes the coal must be under not over 70 feet of overburden. If any of your coal is of this type, let me know.

Yours very truly,

President.

FFK:F

DEFENDANT'S EXHIBIT 221

July 23, 1954

Mr. Herman G. Schenck
801 East Water Street
Princeton, Indiana

Dear Mr. Schenck:

Thank you for your letter of July 19, informing us about the Fort Branch Coal Field.

Inasmuch as we confine our operations to strip mining, we would not be interested in this property.

Very sincerely yours,

President

DEFENDANT'S EXHIBIT 222

June 11, 1956

Mr. Nye F. Morehouse, Special Counsel
Chicago and North Western Railway System
400 West Madison Street
Chicago 6, Illinois

Dear Mr. Morehouse:

Thank you for your letter of June 7 regarding Superior Coal Company.

Our operations are all strip operations, and we are not considering mining deep coal at the present time.

Very sincerely yours,

President

POINTS OF INTEREST

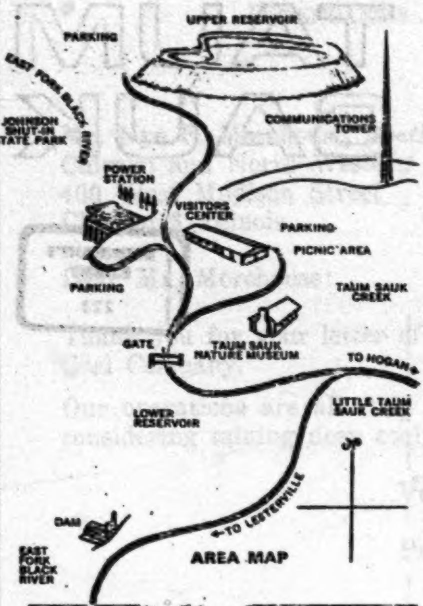
- Petroglyphs—Indian rock carvings in Washington State Park, 10 miles south of De Soto, Mo.
- Moses Austin Resting Place—Potosi, Mo.
- Restored Historic Cabin—Potosi, Mo.
- Mineral Museum—Flat River, Mo.
- Elephant Rocks—Graniteville, Mo.
- Fort Davidson, Pilot Knob Mt., Pilot Knob, Mo.
- Civil War Statue, commemorating site where Ulysses S. Grant was appointed Brigadier General—Ironton, Mo.
- Statues from St. Louis World's Fair of 1904 at home of Chanticleer Ceramics—Ironton, Mo.
- Lake Killarney—4 miles east of Ironton on Hi. 72
- Millstream Gardens—10 miles east of Ironton on Hi. 72
- Taum Sauk Mountain—1772 ft. above sea level; highest point in Missouri
- Johnson Shut-In State Park—Road M near Lesterville, Mo.

ROAD MAP

UNION ELECTRIC COMPANY
315 N. Twelfth Blvd., Saint Louis, Mo. 63166

TAUM SAUK

DEFENDANT'S EXHIBIT
223



Taum Sauk Nature Museum adjoining the Reception Center exhibits natural resources of the state of Missouri. Displays of geological formations, wood and clay resources and their end products, birds and wild flowers, mammals, etc. are included at the museum.

Union Electric Welcomes You!

A by-product of hydroelectric power stations is the opening up and improvement of certain areas that have recreational potential. It is our policy to make the most of that potential for the benefit of the public. This is in keeping with our responsibility as supplier of an essential public service.

You are welcome to enjoy the facilities we have installed to make your visit more comfortable and to provide access to points of interest. We are doing all we can, within the bounds of safety and economy, to conserve and enhance the forests, waters, fish and wildlife that together make the area appealing to you. We ask that you cooperate.

Taum Sauk is the pumped-storage hydro plant of the Union Electric Company, a business managed, investor owned utility serving over 2,300,000 people in Missouri, Iowa and Illinois.

Taum Sauk is one of the few and one of the largest plants of its kind in the world. The Taum Sauk plant serves a special purpose in the power supply of Union Electric, an electric system on which a variation of only seven degrees of daytime summer temperature can cause a load change of as much as the entire capacity of this plant. Pumped hydro is ideally suited to this type of service. A pumped hydro plant is not dependent upon rainfall, since the water required to operate it as a generating plant is pumped into the high elevation lake by its own hydroelectric equipment. Pumping is performed by the simple reversal of rotation of the generating units. Power for this pumping comes from the excess steam turbine generating capacity available at night and over the week ends when the use of electricity by customers is greatly reduced. For each three cheap night kilowatt hours used for pumping, two daytime KWH are returned when they are much more valuable. In addition, the Taum Sauk plant is an important reserve for emergencies.

The rock walls of the upper pool rise 84 feet above the reservoir floor and are concrete lined. They are topped by a 10-foot high parapet wall to permit additional storage of water. The floor is paved with asphalt and covers 39 acres. This reservoir will hold a billion

and a half gallons of water weighing some five million tons, and is 55 acres in area at the top.

Water flows from this upper reservoir down through a vertical shaft 431 feet deep and then races another 400 feet down hill through a tunnel, 6,600 feet long. The lower 1,800 feet of this tunnel is lined with steel tubing 18½ feet in diameter, which carries the water out of the mountain and down to the turbines. From the turbines it passes on into the lower lake. During pumping, this flow is reversed and the water is restored to the upper lake.

The lower lake spreads over nearly 400 acres, and is formed by a small dam across the East Fork of the Black River, which contributed the water for the initial filling and provides a very small amount of water for evaporation and seepage. During generation, the elevation of this lake rises 15 feet in eight hours, and when pumping it drops by the same amount in twelve hours. Level gauges, and automatic valves in this dam, maintain the total volume of water in the two lakes at an amount equal to that of the lower lake when full. In this manner the natural inflow to the lower lake is at all times automatically passed on down stream, except during high flood when some variations may occur.

The Taum Sauk plant has an output rating of 350,000 Kw. Operation is automatic, remotely controlled from the Osage plant and from the Dispatchers' office in St. Louis. The cost of the plant was approximately $50,000,000 and it went into service in the summer of 1963.

We hope that you enjoy your visit and ask you to help us keep the area unlittered so that those who come after you may enjoy their stay.

LOCATION: In Ozark Highlands near Lesterville, Mo. (Reynolds County), 90 airline miles southwest of St. Louis.

COMPLETION DATE: August, 1963.

COST: $50,000,000 (includes $10 million for transmission lines).

CAPACITY: 350,000 kilowatts

NIGHT PUMPING CYCLE: About 9½ hours, using power at rates up to 400,000 kilowatts.

DAY GENERATING CYCLE: Capable of producing 2,750,000 kilowatt hours of energy. Normal full use expected to be about 2,200,000 kwh daily, leaving 25 per cent emergency reserve.

UPPER RESERVOIR: Man-made lake atop a 900-foot mountain, covering an area 55 acres and 92 feet deep, holding 4,350 acre feet of water (8 times the water consumed daily in St. Louis).

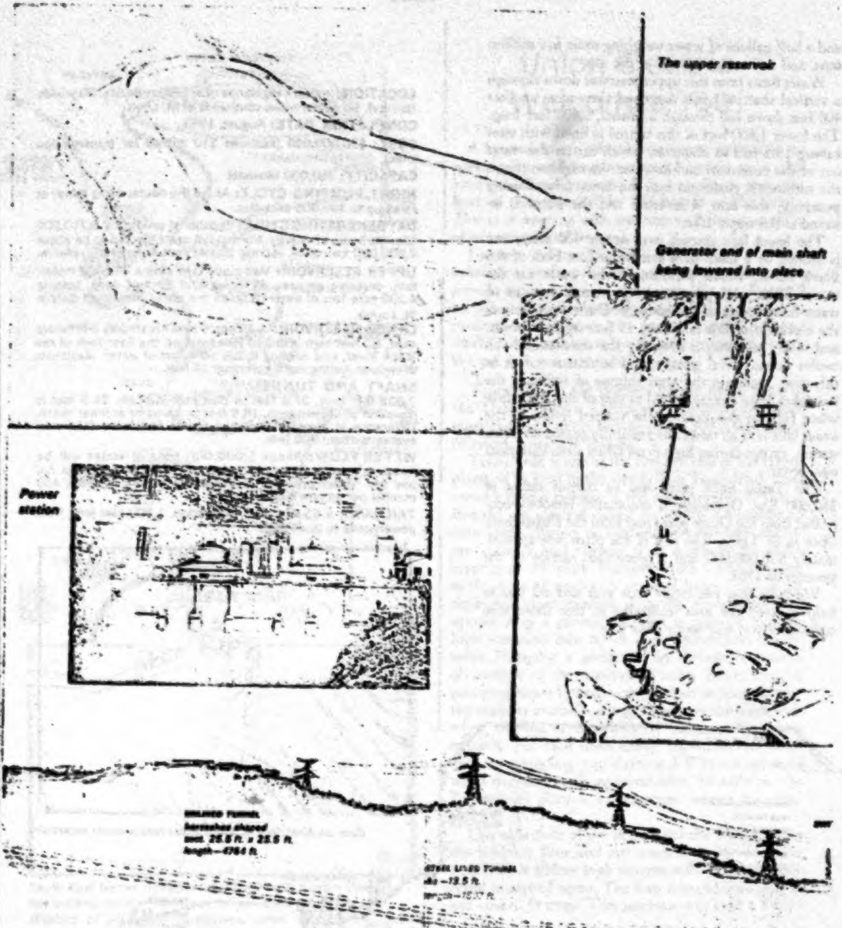
LOWER RESERVOIR: A 395-acre pool created by a concrete dam, 60 feet high and 390 feet long, on the East Fork of the Black River, and holding 6,350 acre feet of water. Maximum drawdown during night pumping: 16 feet.

SHAFT AND TUNNEL:
7,003 feet long, 27.2 feet in diameter at shaft, 25.5 feet in diameter at upper reach, 18.5 feet in diameter at lower reach. Difference in elevation between upper and lower reservoirs averages about 800 feet.

WATER FLOW: About 5,000,000 tons of water will be handled in each direction during the cycle of a normal full use day. Water pressure at the power station is about 400 pounds per square inch.

TAILRACE: A 65-foot wide excavation, 1,500 feet long from powerhouse to lower pool.

Dam on East Fork of Black River forms lower reservoir


The upper reservoir
Generator end of main shaft being lowered into place
Power station
horseshoe shaped
sect. 25.5 ft. x 25.5 ft.
length—4764 ft.
STEEL LINED TUNNEL
dia —13.5 ft.

THE UNIVERSITY OF CHICAGO
Office of Public Information
Chicago, Illinois 60637
MIdway 3-0800, Ext. 4421

70-20
1-19-70

Contact: Stuart Kaminsky
Ext. 4472

DEFENDANT'S EXHIBIT 224

FOR RELEASE: P.M. MONDAY, JANUARY 19, 1970

By 1971, no University of Chicago buildings in the Hyde Park-Kenwood area will be heated by burning coal.

This will complete a conversion program begun in the fall of 1967 to help solve the air pollution problem.

The announcement was made today (Monday) by Gilbert L. Lee, Jr., Vice-President for Business and Finance.

According to Lee, the University owns 236 buildings in the area. A total of 118 of these are heated by the University's steam plant at East 61st Street and South Blackstone Avenue. By September, 1970, the steam plant will be using only gas and oil, not coal.

A total of 95 University buildings which have separate heating plants are now heated by gas or oil. Only 22 buildings, 9.7 per cent, owned by the University are still heated by coal.

"In those 22 buildings and the steam plant," Lee said, "the University is well below the minimum requirement for pollution safety which goes into effect in July, 1970. Only low-sulphur coal is burned. However, those 22 buildings will be converted within a year, possibly sooner."

Conversion of the steam plant to gas will cost more than $2,000,000. The annual cost of heating the main quadrangles by gas will be approximately $250,000 above that which it has cost for heating by coal.

"The University's goal is elimination of air pollution," Lee said. "That goal will be achieved."

# # #

SMK:lh

GENERAL DYNAMICS CORPORATION

DEFENDANT'S EXHIBIT 225

May 25, 1960

Robert A. Bicks, Esq.
Acting Assistant Attorney General
Antitrust Division
Department of Justice
Washington 25, D. C.

Dear Mr. Bicks:

This is a further reply to your letter dated January 29, 1960 to Mr. Earl D. Johnson, President of General Dynamics Corporation, requesting certain information relating to the merger of Material Service Corporation with and into General Dynamics.

We have previously submitted material in connection with Item Nos. 1, 5, 7, 8, and 9 of your letter. I am enclosing herewith the following:

COPY

Exhibit A - A summary of the minutes of each meeting of the Board of Directors of General Dynamics Corporation at which the Material Service merger was discussed. (Item No. 2 of your letter.)

Exhibit B - A list setting forth each merger and acquisition by General Dynamics and by companies it has acquired during the period from January 1, 1953 to date. (Item No. 3)

Exhibit C - Copies of statements submitted to stockholders and filed with certain government agencies in connection with such mergers and acquisitions. (Item No. 4)

Schedule II - A schedule setting forth the total value of sales by General Dynamics of its principal products for each year since 1955. (Item No. 6)

..NAMICS CORPORATION

2 Robert A. Bicks, Esq.
5/25/60

In answer to Item Nos. 10 and 11 of your letter, General Dynamics Corporation had no plans at the time of themerger to use the products and facilities of the Material Service Corporation in its business as it then existed, and at such time there were no plans to use the products and facilities of General Dynamics Corporation in the business of the Material Service Corporation. Since that time the Liquid Carbonic Division of General Dynamics Corporation has supplied Material Service with a portion of its oxygen and acetylene requirements, which are a very minor part of the principal business of the Material Service Division.

In response to Item No. 12, prior to the merger there had been no business transactions between General Dynamics Corporation and Material Service Corporation.

In response to Item No. 13 of your letter, we are submitting a copy of a letter dated November 24, 1959, from Mr. Frank Pace, Jr., Chairman of the Board of General Dynamics Corporation, to the share owners of the Corporation outlining the factors which entered into the decision to merge with Material Service Corporation.

This completes the material submitted in response to your letter. If you have further questions in this connection, please direct them to Mr. Roger I. Harris, Vice President and Chief Counsel of the Corporation, in whose absence I am signing this letter.

Very truly yours,

Ward B. Chamberlin, Jr.
Office of Chief Counsel

WBC, Jr.:dw

encs.

cc: Roger I. Harris, Esq.
Henry N. Marx, Esq.

EXHIBIT C

This Exhibit is submitted in answer to Item 4 requesting "a copy of each statement submitted to stockholders or filed with the Securities and Exchange Commission, stock exchanges, or other public agencies, state or federal, by your company and by each acquired company (except MSC) concerning each merger and acquisition listed in response to the first part of Item 3."

In connection with the mergers and acquisitions of General Dynamics Corporation from January 1, 1953 to date as listed in Exhibit A, the following documents are attached hereto:

Consolidated Vultee Aircraft Corporation

Proxy Statement dated March 26, 1954
SEC Form 8-K for April 1954
New York Stock Exchange Listing Application dated April 30, 1954

Stromberg-Carlson Company

Proxy Statement dated June 1, 1955
SEC Form 8-K for June 1955
New York Stock Exchange Listing Application dated July 1, 1955

J. R. Scantlin Electronics

New York Stock Exchange Listing Application dated September 23, 1955

Electronic Control Systems, Inc.

New York Stock Exchange Listing Application dated September 23, 1955

The Liquid Carbonic Corporation

Proxy Statement dated August 30, 1957
SEC Form 8-K for September 1957
New York Stock Exchange Listing Application dated October 1, 1957

Industrial Air Products of the South

New York Stock Exchange Listing Application dated December 2, 1958

Material Service Corporation

Proxy Statement dated November 24, 1959
Letter to share owners dated December 7, 1959
SEC Form 8-K for December 1959
New York Stock Exchange Listing Application dated December 29, 1959

DEFENDANT'S EXHIBIT 227

November 1, 1963

Mr. R. J. Hepburn:

Re: Kerr Coal Company

In the afternoon of October 29, Mr. Jerry Swanson of the Freeman Coal Company and I visited the Kerr mine. We both went down into the mine and remained there approximately two hours. Mr. Swanson took measurements and checked the roof bolting and the bony sections of the coal, and he possibly will give a more complete report in the very near future.

We obtained a mine map and pinpointed their present workings. However, my impression—although I am not experienced in this type of mining—is that the problems are not insurmountable.

As pointed out in the Joy report, this is a very hard sandstone. There is no definite way of plotting their patterns. However, economical mining could be done. I feel that possibly one of the reasons for the poor report from Joy is that their type of machines are not readily adaptable to these conditions. If a forecast of the location of these sandstone formations could be made, planning could forecast them and a more productive mining situation could be had.

I got the impression in the mine that the men were somewhat lackadaisical, and poor management is one of the main problems. I can see no reason why this could not be a better-cost, more-profit mine than it is at present.

I understand at this time that the Kerr Coal Company is taking penalties because of their B.T.U. requirements. This quite possibly could be due to the fact that the coal loaders in the deep mine do not spearate the rock efficiently. A jig could be set up to do this. The present equipment would probably have to be abandoned and new equipment required: trackage, etc.

I talked to Mr. Kerr relative to the sampling that they do to check the quality of their coal. They have a belt sampler. However, analyses are taken only once a

week, and they have the same problem we have here—comparative analysis between the power company and the coal company.

I would like to add that I feel that Mr. Swanson of Freeman is going to give a much more favorable report than that handed to us by Joy. I let him read the Joy report. He readily agreed with me that this was not a very true picture. I pointedly asked him if he had this mine, could he profitably run it. He said he would jump with joy at the opportunity.

/s/ R. H. Inman
R. H. INMAN

RHI:LJ

Mr. Morris outlined the need for additional stripping equipment at the Fidelity Mine. Present equipment will maintain current production rate in the present pit for approximately eighteen months, at which time, with deeper overburden, the 1650-B would need help to maintain production of approximately 180,000 tons per month.

After mining all of the coal in the present location (Green Pit), the estimated reserves at Fidelity that can be stripped is 23,000,000 tons. This is located in three different areas and shows overburden depths, rock and surface material that would require a machine to help the 1650-B to mine it all out economically. Without a helper, monthly production would be reduced from its current rate of 180,000 tons to approximately 125,000 tons, with resultant cost increase. Also, of this 23,000,000 tons, approximately 10,000,000 could not be mined at all with the one machine (1650-B). The need for additional help is thus established as necessary.

Mr. Morris stated that after thorough investigation, a wheel, properly designed for the particular areas involved, seemed to be the best solution.

The following information and estimates have been developed.

1. Bucyrus-Erie has a standard design and has built a wheel for Peabody and one for Truax. It is high enough for us, but for our purpose certain modifications of design seem necessary. They put a price on their standard deign of $2,500,000, and an estimate on transportation and erection of $400,000.

While we don't know exactly what the change in design we would need would cost, they have indicated that the engineering and other factors involved would cost somewhere in the neighborhood of another $400,000. So it appears we are thinking about something over $3,000,000 for a Bucyrus machine properly designed and in place, ready to operate.

2. We have built four wheels, three of which are now in operation. The W-2 is at Buckheart, the W-3 at Banner, and the W-4 at Cuba. The W-3 was originally at Fidelity Mine but the design of this particular machine did not properly serve the need at that mine and it was not successful there. It was redesigned and moved to Banner and our cost and profit record there will indicate its satisfactory performance.
   The wheels at both Buckheart and Cuba are doing a satisfactory job.

3. We have all of the engineering information and blue prints necessary to build the type of wheel we need at Fidelity. This is quite a cost saving.
   The machine would be built higher, the digging end longer, and the stacker end some longer and higher to place the dirt back far enough in deep overburden to avoid slides. We would use the base, motors and quite a lot of other material from the 5561 Marion shovel which is now a stand-by at Fidelity.

4. Utilizing our engineering knowledge, blue prints, and experience, and building the machine on the site, would effect considerable savings. The repair parts in inventory for the 5561 and also repair parts in inventory for Wheels 2, 3 and 4 would be available for the W-5 machine.

5. Our estimate of the total cost, using our own people for the engineering and supervision, and contracting for the welding, erection and so forth, is $1,800,000.

We feel our estimates are within reason and have included in the above figure $200,000 for contingencies and unexpected difficulties.

In our five-year budget for capital expenditures, we included $250,000 in 1966 and $1,750,000 in 1967.

We can build this machine and have it in operation within fourteen months. The best estimate from Bucyrus is eighteen months and probably longer.

After discussion, upon motion duly made by Mr. Nugent, and duly seconded by Mr. Thorson, the following resolution was unanimously adopted:

> RESOLVED, that management be authorized to proceed with the necessary purchasing and contractual arrangements to build Wheel No. 5 for use at the Fidelity Mine at a cost of not to exceed $1,800,000.

The Chairman then stated that the next order of business was consideration of the payment of a dividend. He presented a certificate by Mr. John T. Murray, Treasurer of the Company, in respect of the Company's current financial condition and related matters, and stated that such certificate would be made a part of these minutes.

After discussion, upon motion duly made by Mr. Thorson, and duly seconded by Mr. Ames, it was unanimously

> RESOLVED, that a regular dividend of forty-five cents (45¢) per share on the common stock of this Company be and the same hereby is declared, payable on the 9th day of September, 1966, to stockholders of record at the close of business on August 24, 1966.

There being no further business, on motion duly made by Mr. Thorson, and duly seconded by Mr. Gebhart, the meeting was adjourned.

John T. Murray
Secretary

DEFENDANT'S EXHIBIT 229

Form Number 250

PLEASE SEE ENCLOSED INSTRUCTIONS BEFORE COMPLETING QUESTIONNAIRE

1. Company and address (please include zip code) Freeman Coal Mining Corporation
307 North Michigan Avenue
Chicago, Illinois 60601

2. Name & title of officer supervising compliance with subpoena M. J. Proper
Administrative Vice President

COAL RESERVE ESTIMATE

The estimated tonnage should include all coal owned in fee, under lease or optioned by your company and any subsidiary, affiliate, division or nominee as of the most recent compilation. Only reserves located in mining districts 9, 10 and 11 (Illinois, Indiana or West Kentucky) need be shown.

3. COAL RESERVES DEDICATED TO EXISTING MINES:

NAME OF MINE	Estimated Strip Tonnage (Tons)	Estimated Deep Tonnage (Tons)	Percentage of Recovery Used for Estimated Tonnage: Strip	Percentage of Recovery Used for Estimated Tonnage: Deep
Crown		20,719,552		50.00%
Orient No. 3		33,532,320		74.42
Orient No. 4		5,315,408		74.42
Orient No. 5		34,035,600		74.42
Orient No. 6		55,730,400		74.42
Total Tons:		149,333,280		

4. OTHER COAL RESERVES (owned, leased, or optioned by your company or any subsidiary, affiliate, division or nominee, as of most recent compilation, located in mining districts 9, 10, and 11 (Illinois, Indiana, and West Kentucky)):

COUNTY	STATE	Estimated Strip Tonnage (Tons)	Estimated Deep Tonnage (Tons)	Percentage of Recovery Used for Estimated Tonnage	
				Strip	Deep
Jefferson	Illinois		97,961,664		74.42%
Williamson	Illinois		16,498,272		74.42
Macoupin	Illinois		55,456,800		50.00
Christian	Illinois		11,642,400		50.00
Montgomery	Illinois		141,034,992		50.00
Sangamon	Illinois		11,760,000		50.00
	Total Tons:		334,354,128		

5. Explain briefly methods used for determining percentage of recovery for both strip and deep tonnage:

Present and past experience in mining these seams.

6. Information supplied is as of December 31, 1968.

1089 ~~1836~~

DEFENDANT'S EXHIBIT 230

ILLINOIS POWER COMPANY

500 SOUTH 27TH STREET, DECATUR, ILLINOIS 62525

April 13, 1970

Mr. Donald G. Kempf, Jr.
Kirkland, Ellis, Hodson,
Chaffetz & Masters
130 East Randolph
Chicago, Illinois 60601

Dear Mr. Kempf:

This letter will confirm our phone conversation of April 11. As I advised you then:

1. Illinois Power Company has given consideration to nuclear energy as an alternative to coal in the past and will certainly compare the overall costs of fossil and nuclear in planning future generation;

2. Illinois Power Company had been aware of the United Electric-Freeman affiliation since around 1960 when Frank Nugent and the other representatives of the Crown interests went on United's Board and Johnny Morris replaced Frank Kolbe as President; and

3. Because of the location of the United Electric and Freeman mines as related to the generating stations of Illinois Power Company we had not regarded the two companies as competitors with respect to service to any particular station. Freight costs prevented such competition. After the combination of the two companies this same situation continued so long as I was President of the Company.

Very truly yours,

Allen Van Wyck
Chairman of the Board

1070
~~4039~~

DEFENDANT'S
EXHIBIT
231

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY
GENERAL OFFICES / 607 EAST ADAMS / SPRINGFIELD, ILLINOIS 62701

April 14, 1970

Mr. Donald G. Kempf, Jr.
Kirkland, Ellis, Hodson, Chaffetz & Masters
Room 2900 Prudential Plaza
Chicago, Illinois 60601

Dear Mr. Kempf:

In re United States v. General Dynamics Corporation, et al., Civil No. 67 C 1632 (N.D. Illinois)

This letter will confirm your discussion of the above lawsuit with representatives of our company a few weeks ago. We reviewed with you then the competitive situation concerning the coal supply at our four stations.

1. Our Meredosia generating station is on the Illinois River, in the area generally served by mines in the Fulton-Peoria freight district. We have purchased some dust from Freeman's Crown Mine in the Springfield freight district for this station in the past, but that is no longer available. Because of the transportation charges, screenings from the Springfield freight district would not be competitive with river coal at Meredosia.

2. Coffeen is a mine-mouth generating station, and it would not be possible for mines other than that at the station to compete for its coal business.

3. The only United Electric coal we consume at our Grand Tower generating station is a small amount of carbon.

4. The Hutsonville generating station is in the far eastern portion of Illinois, near the Indiana border, and could not be reached on a competitive freight rate by either United Electric or Freeman.

You have indicated that there might be some confusion concerning the meaning of paragraph 4 of our letter to Mr. Turner, of the Department of Justice, dated October 28, 1966. In the past and

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY

currently, we have found that the prices of each of the two companies for coal offered to the Central Illinois Public Service Company have always been competitive with other available suppliers. We have no idea what effect, if any, the Freeman-United Electric combination will have upon our coal prices in the future.

You have advised us that the Department of Justice has designated our letter of October 28, 1966 as an exhibit in the above lawsuit. In view of this we are pleased to supply you with the information set forth above.

Yours very truly,

K E Bowen

K. E. Bowen
President

KEB/bp

MAPP

MAPP goals and accomplishments parallel the power development patterns of utility integration and savings for consumers proposed in the Federal Power Commission's National Power Survey Report issued late in 1964.

MAPP membership of midwestern power suppliers has more than doubled in less than three years.

MAPP is investigating the feasibility, timing and routing of transmission lines required to integrate the huge hydro-electric potential in Canada with power developments in the United States.

MAPP individual utilities originally planed to install about 70 generating units between 1967-80. Through regional planning the member systems now plan to install only about 35 units but the average size of each will be approximately doubled. This and other generation economics will result in savings of $268 million during this period.

MAPP will operate a Coordination Center which will ultimately employ a high speed central computer to coordinate regional power operations.

These accomplishments coupled with high voltage line construction have demonstrated that locally controlled power suppliers of all types of ownership working voluntarily together will provide the most dependable service at the lowest possible cost.

MAPP

1 CANADIAN CROWN CORPORATION

Manitoba Hydro-Electric Board

14 INVESTOR-OWNED ELECTRIC UTILITY COMPANIES

Black Hills Power and Light Company
Interstate Power Company
Iowa Electric Light and Power Company
Iowa-Illinois Gas and Electric Company
Iowa Power and Light Company
Iowa Public Service Company
Iowa Southern Utilities Company
Lake Superior District Power Company
Minnesota Power & Light Company
Montana-Dakota Utilities Co.
Northern States Power Company
Northwestern Public Service Company
Otter Tail Power Company
Union Electric Company

26 MUNICIPAL ELECTRIC UTILITIES

Adrian, Minnesota
Alexandria, Minnesota
Ames, Iowa
Austin, Minnesota
Cedar Falls, Iowa
Delano, Minnesota
Detroit Lakes, Minnesota
Fairfax, Minnesota
Fairmont, Minnesota
Glencoe, Minnesota
Hutchinson, Minnesota
Kenyon, Minnesota
Lake Crystal, Minnesota
Madelia, Minnesota
Marshall, Minnesota
Mazeppa, Minnesota
Melrose, Minnesota
Moorhead, Minnesota
Muscatine, Iowa
New Ulm, Minnesota
Owatonna, Minnesota
Redwood Falls, Minnesota
Sleepy Eye, Minnesota
Watertown, South Dakota
Windom, Minnesota
Worthington, Minnesota

2 PUBLIC POWER DISTRICTS

Omaha Public Power District
Consumers Public Power District

7 RURAL ELECTRIC G&T COOPERATIVES

Cooperative Power Association
(15 distribution cooperatives)
Dairyland Power Cooperative
(27 distribution cooperatives)
Eastern Iowa Light and Power Cooperative
Minnkota Power Cooperative
(12 distribution cooperatives)
Northern Minn. Power Association
(8 distribution cooperatives)
Rural Cooperative Power Association
(5 distribution cooperatives)
Southwestern Federated Power Cooperative
(8 distribution cooperatives)

DEFENDANT'S EXHIBIT 232

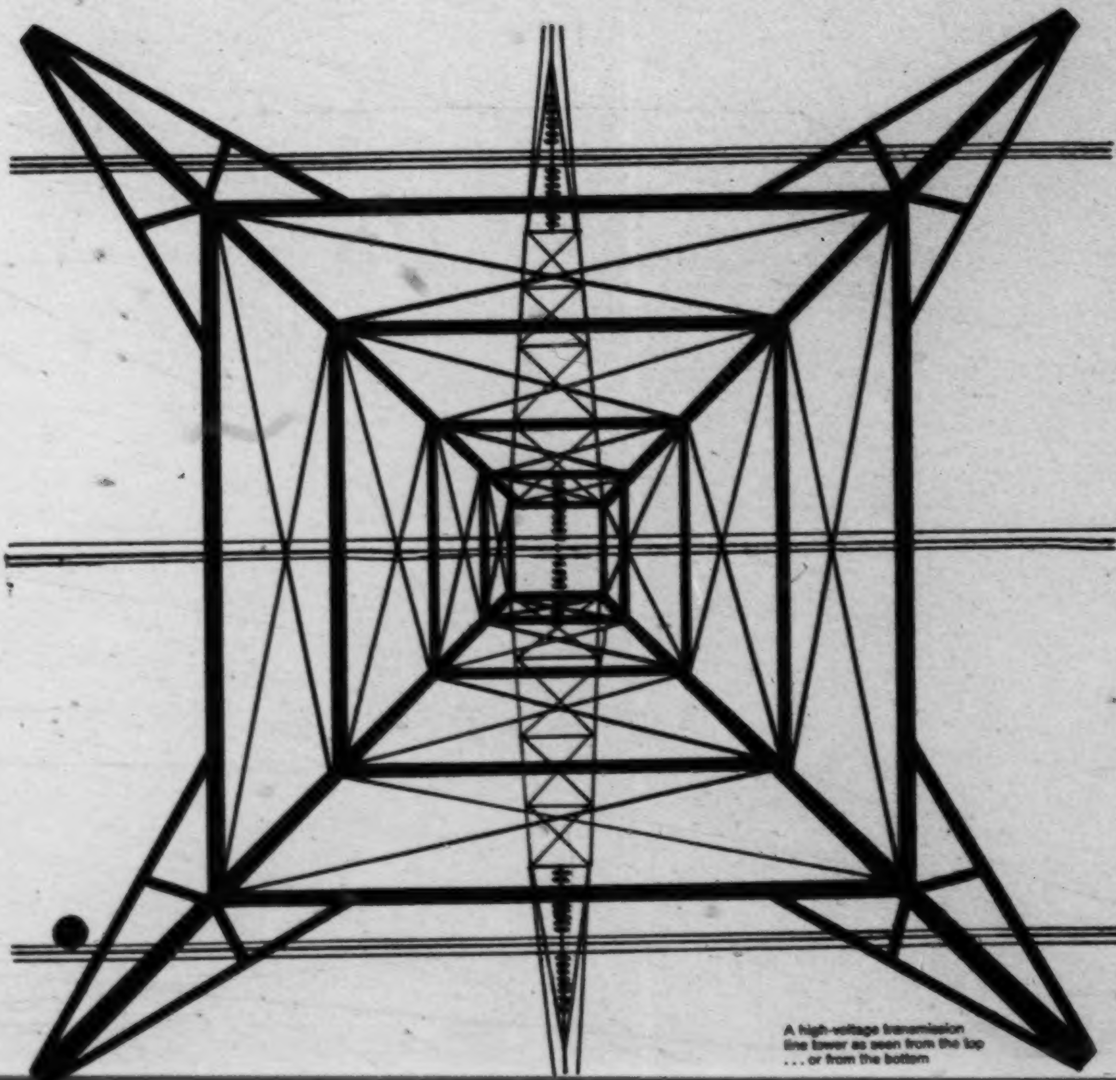
Low Cost Electric Power And Dependability

...Through

Mid-America Interpool Network

main

DEFENDANT'S EXHIBIT 233



A high-voltage transmission line tower as seen from the top . . . or from the bottom

At 5:12 p.m., May 15, 1968, a devastating tornado struck the central part of Illinois. Eighty-six steel towers were toppled with two 345,000-volt lines carrying power 200 miles from a generating station at Kincaid, Illinois, to a bustling rush-hour Chicago. Twenty miles of extra-high voltage transmission lines were torn down.

Both direct connections for energy from Kincaid to Chicago were broken.

Yet, in Chicago, power continued to flow without interruption to Commonwealth Edison Company customers. Elevators ran in high-rise buildings. Rapid transit electric trains moved downtown throngs home. Throughout the metropolitan area, housewives prepared evening meals. Children's TV was not disturbed.

Kincaid maintained its production as transmission lines of MAIN partners—Illinois Power Company, Central Illinois Public Service Company, and others—relayed the energy to other lines serving Chicago.

Years of planning paid off in an emergency, automatically.

This was **main** at work.


main
The Mid-America Interpool Network
is an organization of power systems
serving major load centers in the Middle West.
There are 19 regular members consisting of
18 investor-owned power companies
and one rural electric association.
In addition, there are four liaison members
from an adjacent coordinating group.
Also, associate memberships are available to
municipal and other small electric systems.
MAIN's prime purpose is to assure
the reliability of electric power production
and transmission throughout the region it
serves. How does it work?
MAIN members coordinate such functions as
planning, construction and utilization of
generating and transmission facilities
on a basis that takes into account
the needs of the entire region.
This enables all MAIN
affiliates to engineer, build, maintain
and operate their respective
power supply systems in a manner consistent
with the utmost dependability and efficiency.
members
REGULAR MEMBERS:
Commonwealth Edison Company
Illinois Group
Central Illinois Light Company
Central Illinois Public Service
Illinois Power Company
Missouri Group
Associated Electric Cooperative
Union Electric Company
Eastern MAPP Group
Interstate Power Company
Iowa Electric Light and Power
Iowa-Illinois Gas and Electric
Iowa Power and Light
Iowa Public Service
Iowa Southern Utilities
Northern States Power
Wisconsin-Upper Michigan Systems
Madison Gas and Electric
Wisconsin Electric
Wisconsin Power and Light
Wisconsin Public Service
Upper Peninsula Power
LIAISON MEMBERS:
American Electric Power
Indiana Group
Indianapolis Power
Northern Indiana Public
Public Service Indiana

organization

Historically, MAIN is an outgrowth of a trend that developed in the early 1930's when Midwest power companies began to connect their transmission lines to each other to fortify their reliability and gain the advantages of diversity and economy. After World War II, these interconnections were expanded and the philosophy and techniques of network activity developed rapidly.

During the last decade, increases in generating unit size and improvements in the technology of extra-high voltage transmission have lent themselves naturally to a dual objec. :
(1) Increased reliability and protection from large-scale outages by planned utilization of available power from neighboring utilities, and
(2) Economies resulting from coordinated scheduling of new production and transmission facilities and the maintenance of such equipment. The coordinated management of interconnected generating units and transmission lines has also enabled MAIN companies to utilize to the best advantage any surplus power that becomes available on a day-to-day basis from larger, more economical units.

More or less informal, yet binding, agreements gradually drew MAIN members closer and closer together in mutual planning and led to the formal organization of the Mid-America Interpool Network in November 1964.

MAIN and the forerunning associations of its members have compiled a long history of working for reliability of service through coordinated planning and operation of interconnected power systems. Members of MAIN aided in the preparation of the Federal Power Commission National Power Su. .y

and some of the policies and patterns established by MAIN are considered models of inter-company system cooperation.

The accompanying map exhibits the geographic expanse of MAIN and its overlapping relationships with other regional power groups. It should be noted that American Electric Power system and three Indiana utilities as liaison members of MAIN provide coordinated relationships with power systems to the east. To the west, Union Electric Company in St. Louis maintains liaison with the Missouri-Kansas Pool for additional avenues of cooperation. Toward the northwest, some of the MAIN area overlaps the area of the Mid-Continent Area Power Planners (MAPP). To the south, Associated Electric Cooperative, Inc. provides access to relationships with the Southwest Power Pool. And the Illinois-Missouri companies and AEP are in coordinated contact with the Tennessee Valley Authority to the southeast.

As a result, MAIN is the Midwest hub of a power pooling effort that directly affects and improves the reliability of electric service to 23,100,000 people in nine states. And through its coordinated relationships with other pools and systems, it vitally aids the cause of reliability through a much wider region of 15 states.

how main operates

The work of MAIN is performed by an Executive Committee consisting of representatives from each of the participating major groups, and by Engineering and Operating Committees. Their function is to do the detailed work of system coordination . . . to improve the already high reliability of the power supply in the Midwest.

MAIN's Engineering Committee regularly tests the soundness of individual company and pool plans by reviewing their effect on the region. To accomplish this, the Committee studies such matters as regional transmis . power flows for normal and emergency system conditions, system stability, and the ability of the interconnected systems in the region to cope with possible major catastrophes.

By using high-speed computers to perform the needed complex studies, the committee examines specific conditions expected during peak load periods and other critical times. These studies provide information to system operators to help them anticipate and solve problems that may be encountered.

An important function of the Engineering Committee is long-range planning. The committee analyzes the future development of extra-high voltage EHV transmission systems and interconnections among the systems to assure reliable performance.

The MAIN Operating Committee's activities include the establishment of adequate communication channels between companies, coordination of generating unit maintenance, formulation of procedures for system protection and investigation of disturbances of major consequence.

The MAIN Coordination Center has been operating in the Commonwealth Edison Building in Chicago since April 1, 1967. This Center maintains hour-by-hour communications with the major members of the MAIN group and with similar centers in other regions. Its staff collects, analyzes and disseminates information on all operating conditions in the region which might affect interconnected operations. Here, maintenance down time or planned outages of major generating and transmission facilities are closely coordinated to avoid combinations of outages which might threaten system reliability. By such activities, the Center provides an operating overview of the entire region—for the entire region.

New major generating facilities for the

main

Mid-America Interpool Network

Company	Station
American Electric Power Company	Big Sandy No. 2 Mitchell No. 1 Mitchell No. 2 J. E. Amos No. 1 J. E. Amos No. 2 D.C. Cook No. 1 D.C. Cook No. 2 Unidentified Unidentified
Associated Electric Cooperative	Thomas Hill No. 2 New Madrid
Central Illinois Light Company	Edwards No. 3
Central Illinois Public Service Company	Coffeen No. 2
Commonwealth Edison Company	Dresden No. 2 Dresden No. 3 Quad-Cities No. 1 Quad-Cities No. 2 Zion No. 1 Powerton No. 5 Zion No. 2
Illinois Power Company	Baldwin No. 1 Baldwin No. 2
Indianapolis Power & Light Company	Petersburg No. 2
Interstate Power Company	M.C. Kapp 3
Iowa Electric Light and Power Company	Duane Arno[illegible]
Iowa-Illinois Gas and Electric Company	Quad-Cities No. 1
Iowa Power and Light Company	Cooper
Iowa Public Service Company	Neal No. 2
Northern Indiana Public Service Company	D.H.M. No. 11 Unidentified
Northern States Power Company	Monticello Prairie Island No. 1 Prairie Island No. 2
Public Service Indiana	Cayuga No. 1 Cayuga No. 2
Wisconsin Electric Power Company	Valley No. 2
Wisconsin Electric Power Company Wisconsin Michigan Power Company	Point Beach No. 1
Wisconsin Electric Power Company Wisconsin Michigan Power Company	Point Beach No. 2
Wisconsin Power and Light Company	Edgewater No. 4
Wisconsin Public Service Corporation Wisconsin Power and Light Company Madison Gas and Electric Company	Kewaunee No. 1
Union Electric Company	Labadie No. 1 Labadie No. 2 Labadie No. 3 Labadie No. 4
Upper Peninsula Power Company	Unidentified

*Quad-Cities No. 1 is an [illegible] kw unit, jointly owned by Commonwealth Edison Company and Iowa-Illinois Gas and Electric Company

**Cooper unit for which Iowa Power and Light Company has made a 30 year contract for [illegible] mw in the Iowa Pool. This will be an [illegible] kw unit located in Nebraska and owned by Consumers Public Power System.

Capacity, Kw.	Type	Serv. Date
800,000	Fossil	Sept., 1969
800,000	Fossil	June, 1970
800,000	Fossil	Feb., 1971
800,000	Fossil	July, 1971
800,000	Fossil	March, 1972
1,100,000	Nuclear	April, 1972
1,100,000	Nuclear	April, 1973
1,300,000	Fossil	Oct., 1973
1,300,000	Fossil	April, 1974
290,000	Fossil	June, 1969
600,000	Fossil	April, 1972
350,000	Fossil	Jan., 1972
600,000	Fossil	March, 1972
800,000	Nuclear	Jan., 1970
809,000	Nuclear	Dec., 1970
*405,000	Nuclear	Jan., 1971
809,000	Nuclear	Jan., 1972
1,100,000	Nuclear	April, 1972
840,000	Fossil	April, 1972
1,100,000	Nuclear	May, 1973
600,000	Fossil	June, 1970
600,000	Fossil	Jan., 1973
450,000	Fossil	July, 1969
[illegible]00	Fossil	May, 1975
5[illegible],000	Nuclear	Dec., 1973
*404,000	Nuclear	Jan., 1971
**389,000	Nuclear	April, 1972
325,000	Fossil	June, 1972
110,000	Fossil	June, 1970
400,000	Fossil	June, 1973
545,000	Nuclear	May, 1970
550,000	Nuclear	May, 1972
550,000	Nuclear	May, 1974
503,000	Fossil	May, 1970
508,000	Fossil	May, 1972
140,000	Fossil	June, 1969
497,000	Nuclear	April, 1970
497,000	Nuclear	April, 1971
330,000	Fossil	Dec., 1969
525,000	Nuclear	June, 1972
600,000	Fossil	Jan., 1970
600,000	Fossil	Jan., 1971
600,000	Fossil	Jan., 1972
600,000	Fossil	Jan., 1973
107,000	Fossil	Jan., 1973

reliability and the future

Reliability is not a stand-still thing.
Projection of electric load growth shows that the nation will need twice as much power producing capability in 1980 as required in 1970.
In building for this future growth, the coordinated planning and performance of MAIN companies will produce their greatest benefit.

In 1968 alone, MAIN members strengthened their interconnected power supply systems with the addition of 4.5 million kilowatts of generating capacity, a 12.3 percent increase.
In the same year, 600 miles of new 345,000-volt transmission lines were added, a 16 percent increase.

During the five years, 1969 through 1973, MAIN companies plan to install 28 million kilowatts of generating capacity, a growth of 55 percent.
In that period too, the transmission system will be strengthened by the construction of over 3700 miles of 345,000-volt lines, an increase of 85 percent.
Also, a network of 765,000-volt lines will be placed in service to provide a new and stronger backbone for the interconnections that tie MAIN companies together.
Each 765,000-volt line will have the capacity to move 4,000,000 kilowatts from one location to another.

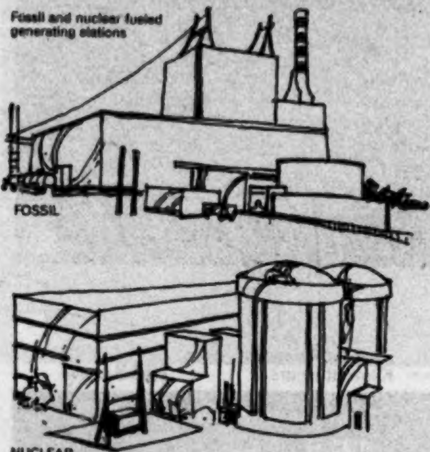
The extra-high voltage transmission system in Mid-America will continue to expand and possibly reach the stage shown in the 1980 map.

This growth, with reliability and strength as its core, calls for maximum planning and effort.

That is the story of

main

main
highlights



Generating Capacity Kilowatts* **42.5 million**

27.5

LIAISON MEMBERS
15 million

JANUARY 1, [illegible]

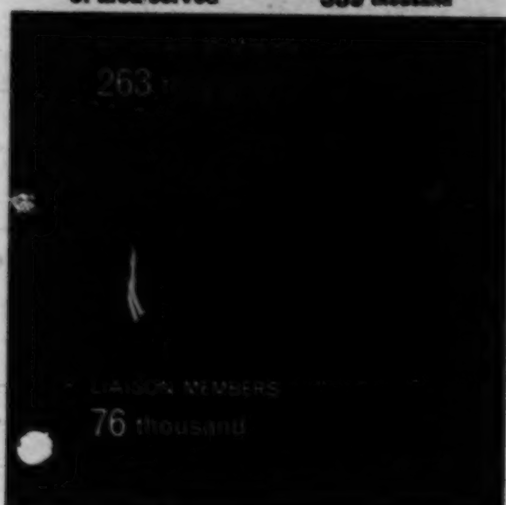
Peak Load Kilowatts **38.5 million**

Energy Sales
Kilowatt Hours **198.8 billion**

Miles of transmission lines **27.7 thousand**

JANUARY 1, [illegible]

Square miles of area served **339 thousand**



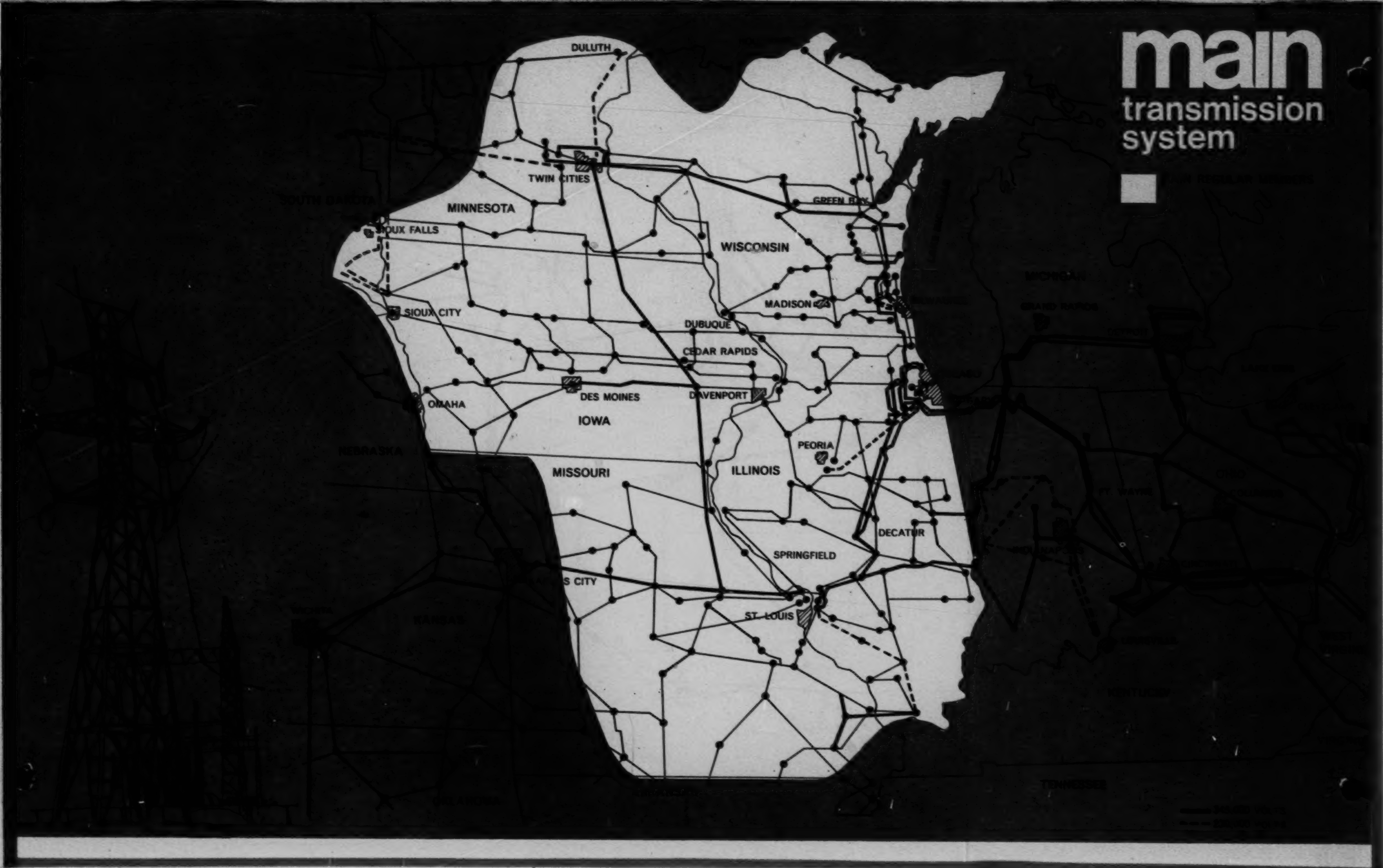
JANUARY 1, [illegible]

Number of customers **9.7 million**

JANUARY 1, [illegible]

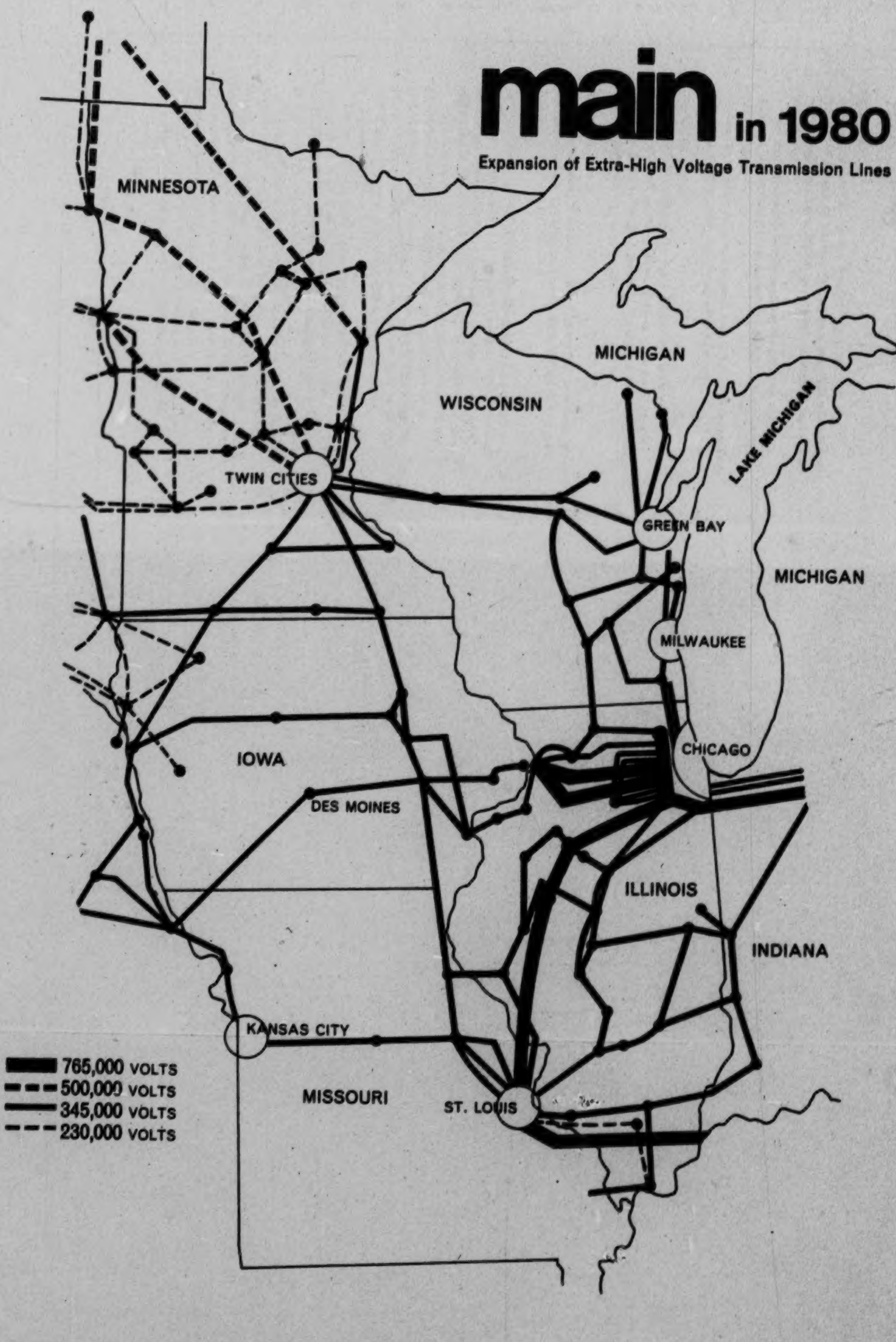
Population **33.5 million**

JANUARY 1, [illegible]


main
transmission
system
DULUTH
TWIN CITIES
MINNESOTA
SOUTH DAKOTA
SIOUX FALLS
WISCONSIN
GREEN BAY
MICHIGAN
MADISON
SIOUX CITY
DUBUQUE
CEDAR RAPIDS
DES MOINES
DAVENPORT
OMAHA
IOWA
NEBRASKA
PEORIA
MISSOURI
ILLINOIS
DECATUR
SPRINGFIELD
ST. LOUIS

main in 1980

Expansion of Extra-High Voltage Transmission Lines

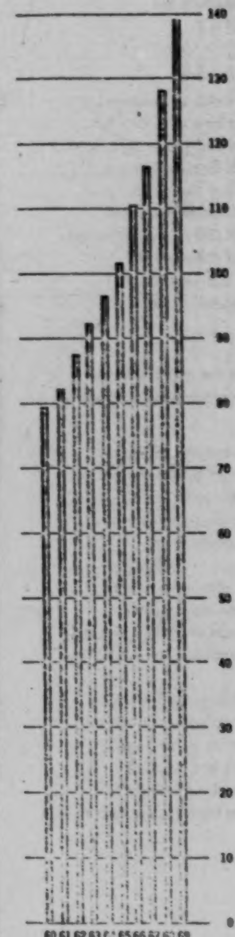


DX 234

Illinois Power Company - Annual Report 1969

* * *

ELECTRIC REVENUES
Millions of Dollars



Progress in '69

EARNINGS

Earnings per share of common stock in 1969 were $2.67. The increase of 24 cents per share, or 9.9 per cent, over 1968 was achieved even though there were 500,000 more shares outstanding than at the end of 1968.

Net income, which is before provision for preferred stock dividends, was $37,668,000, compared with $33,337,000, an increase of 13 per cent.

Total earnings for the common stock were $35,557,000 as compared with $31,226,000 in 1968, an increase of 13.9 per cent.

DIVIDEND

At its September meeting, the Board of Directors declared a quarterly dividend on the common stock of 50¢ a share, payable November 1, 1969. This is an increase of 5 cents over the previous quarterly dividend.

REVENUES

Revenues from sales of electricity were $138,909,000, an increase of 8.5 per cent over 1968. Gas revenues were $73,825,000, up 11.3 per cent.

ELECTRIC

Electric sales of 7,972,000,000 kilowatt-hours were 9.5 per cent higher than in 1968. Sales to industrial customers, which accounted for 53.6 per cent of all kilowatt-hour sales, were up 10.4 per cent, slightly higher than the increase in commercial and residential sales.

To help meet the increasing demand for electric power in our growing territory, the first 600,000 kilowatt unit of our electric generating station near Baldwin in Southern Illinois is scheduled to go into operation in time for the summer peaks of 1970. Work on a second unit of the same size, scheduled to begin operations in 1973, has begun.

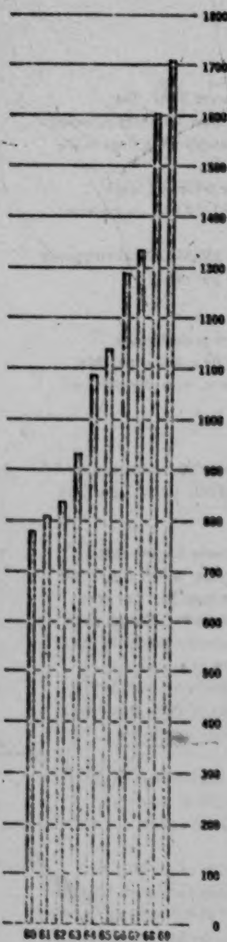
Two 345,000-volt transmission lines from Baldwin station to areas of heavy industry on the Illinois side of the St. Louis metropolitan area are scheduled to be completed before the first unit goes into service.

As a further step to strengthen our capability of meeting peak demands in 1970 and in the future, the Company purchased 170,000 kilowatts of gas turbine generators. Of this, 100,000 is being installed near Granite City and will be ready for service by late spring. The other 70,000 kilowatts being installed near La Salle may be delayed because of a strike against the supplier.

Scheduled construction of electric facilities over the next five years is expected to total $523 million, about $292 million for

* * *

ELECTRIC PEAK LOADS
In Thousands of Kw



TAXES
In line with national trends, property and other general taxes have continued to increase. In addition, on August 1, 1969, the State of Illinois imposed a 4 per cent income tax on corporations. However, amendment of federal tax laws to reduce the surcharge from 10 per cent to 5 per cent, effective January 1, 1970, and to eliminate this tax on July 1, 1970, will tend to reduce the impact of these increased taxes.

FINANCING
The Company sold 500,000 shares of common stock in January, 1969, at a net price of $18,825,000. The sale of $35 million of 8.35% First Mortgage Bonds in October, 1969, provided an additional $34,694,000. The sale of these securities, together with short-term bank loans, provided the new cash required by the Company during the year.

In January, 1970, the Company sold 500,000 additional shares of its common stock. This sale provided $15,738,000 of the estimated $70 million of new cash which will be required during 1970. The balance of such funds will be provided by the issuance of additional securities, through short-term bank loans, or both.

ENVIRONMENT
Environmental pollution has emerged as one of the nation's most difficult and urgent problems. For our Company, the main problem is air pollution.

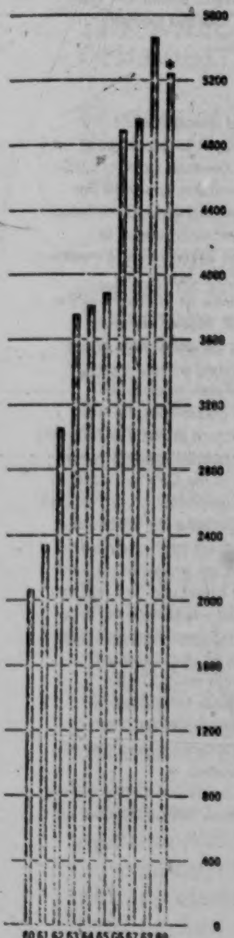
Equipment is available for removing particulate matter from stack emissions and our plans have been approved by the Illinois Air Pollution Control Board to meet its standards for particulates. These plans include installation of electrostatic precipitators, along with other steps. Over the next five years we expect to spend some $16 million on this program.

Technology has not yet been developed to eliminate sulphur oxides from stack emissions. To hasten such development, we are taking part in various studies and research projects and are following with interest the work of others. We are also studying the availability, cost, and feasibility of other fuels.

The Illinois Commerce Commission, by which our Company is regulated, is conducting an investigation of air pollution by electric utility companies in the state. We have appeared at its hearings and expect to be called upon for additional data and testimony.

At this point—with standards, regulations, and technology all in a period of change and formation—there is no basis for any accurate

GAS PEAK LOADS
In Thousands of therms

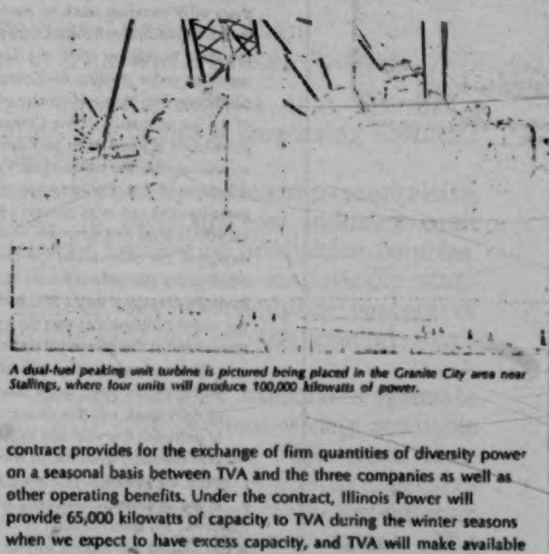


* On Jan. 8, 1970, a new peak of 6450 occurred.

estimation of the eventual cost to our Company and our customers of doing our part in cleaning up the air.

INTERCONNECTIONS

Our Company, Central Illinois Public Service Company, and Union Electric Company entered into a contract in November, 1969, with Tennessee Valley Authority providing for new interconnection facilities between the systems of the three companies and TVA. The



A dual-fuel peaking unit turbine is pictured being placed in the Granite City area near Stallings, where four units will produce 100,000 kilowatts of power.

contract provides for the exchange of firm quantities of diversity power on a seasonal basis between TVA and the three companies as well as other operating benefits. Under the contract, Illinois Power will provide 65,000 kilowatts of capacity to TVA during the winter seasons when we expect to have excess capacity, and TVA will make available to the Company 65,000 kilowatts of capacity during our peak summer seasons when TVA expects to have excess capacity. This arrangement begins in November of 1972.

Union Electric has notified our Company and Central Illinois Public Service Company of the termination of the interconnection agreement under which the Illinois-Missouri Pool has operated since 1952. Termination of the contract becomes effective April 1, 1972. Prior to that time, new interchange agreements will be negotiated between the companies which will provide benefits similar to those in the present agreement.

Workmen installing gas regulator station.

Our Company has other interconnection agreements with the American Electric Power system, Commonwealth Edison Company, Central Illinois Light Company, Iowa-Illinois Gas and Electric Company, and Electric Energy, Inc.

CIPS ACQUISITION

On March 28, 1968, the Company and Central Illinois Public Service Company announced a proposal to offer to exchange .65 of a share of IP common stock for each share of common stock of CIPS. In March, 1969, the Illinois Commerce Commission approved the proposal. In January, 1970, the Securities and Exchange Commission issued an order granting the Company's application subject to conditions—(1) that appropriate provision be made for the divestment of the gas properties of the Company and CIPS and (2) that jurisdiction is reserved to pass upon the fairness of the terms of the acquisition and the terms of such divestment. Neither company will proceed with the exchange offer unless the divestment of the gas properties can in its opinion be accomplished without injury to its stockholders or customers. Studies undertaken prior to the receipt of the order under the then known possibilities did not develop any plan which would not result in such injury. The following footnote contained in the SEC findings and opinion accompanying the order contemplates that the acquisition of the CIPS stock and divestment of the gas properties may be accomplished on such a basis:

> "The companies may appropriately determine the nature and timing of any steps to be taken with respect to the acquisition of CIPS stock and the divestment of the gas properties in light of pertinent financial and money-market conditions. The reasonable flexibility available to the companies would thus not foreclose the selection of a program entailing more than one stage in the interests of feasibility and fairness to all concerned."

However, the determination of whether such a result can be accomplished will require further study by both companies. If this appears possible, further proceedings before the SEC and the Illinois Commerce Commission and acceptance or approval of stockholders of both companies will be required.

The SEC denied a contention of certain holders of CIPS preferred stock that the approval of the application should be conditioned on the elimination of the CIPS preferred.

* * *

DEFENDANT'S EXHIBIT 235

THE WALL STREET JOURNAL, Monday, April 6, 1970
COMMODITIES

Shortage of Low-Sulphur Coal Hampers
Electric Utilities in Antipollution Efforts

By THOMAS LINDLEY EHRICH
Staff Reporter of THE WALL STREET JOURNAL

PITTSBURGH — Electric utilities that are being pressed to cut pollution are facing a perplexing obstacle: A shortage of low-sulphur coal.

Developed reserves aren't nearly sufficient to meet rising demand from utilities. In fact, the coal industry can't even meet present demand because of production troubles. And while potential U.S. reserves are statistically staggering—some 1.02 trillion tons with sulphur content of 1% or less—getting this coal out of the ground won't be done easily or soon.

Nor will it come cheaply. Mining executives estimate that low-sulphur coal, if it ever becomes widely available for utility use, will cost as much as 50% more than medium and high-sulphur coals. This is due to expensive mining conditions generally associated with low-sulphur coal, plus the big expense of opening new mines. The price could go even higher if utilities are forced to bid against the steel industry, the prime user of low-sulphur coal.

Such cost and availability problems will directly affect pollution-control planning by many utilities, particularly the coal-burning plants that provide more than half the nation's electricity. These utilities are in the process of deciding how to meet stringent curbs on sulphur dioxide emissions, and many hope to switch to low-sulphur coal.

Difficulties in making such a switch could encourage some utilities to drop coal entirely, moving to low-sulfur fuel oil, to sulphur-free fuels such as natural gas or to increased reliance on nuclear power. The coal industry, however, hopes utilities will install stack-gas cleaning

devices, thus permitting continued use of medium and high-sulphur coals.

Less than one-quarter of the coal burned by electric utilities these days is low-sulphur coal. (Low-sulphur generally means sulphur content of 1% or less, though some states are setting a 1.5% limit.) Sulphur content of the rest ranges up to about 6%, with the bulk of utility coal use in the 1.6% to 3.5% range. In recent years, use of coal toward the top end of the sulphur-content scales has increased due to improvements in furnace efficiency.

Moving out of this coal-buying pattern couldn't be done in the current market. Nowadays, mine output is committed under long-term contract. Existing mines are operating at capacity, so new mines would be needed to meet increased utility demand. (For the moment, at least, steelmakers have the inside track on new supplies of low-sulphur coal. Reserve stockpiles at U.S. mills are dangerously low due to coal production shortfalls the past two years, and foreign steel companies are starting to bid aggressively for U.S. coal.)

Less than one-fourth of known U.S. low-sulphur coal reserves is the bituminous coal burned by nearly all coal-fired steam plants. Some 78% of the total represents subbituminous coal and lignite, grades that couldn't be used in the bituminous-fired plants without expensive boiler alterations.

The 21% that is bituminous coal isn't an insignificant amount, of course. These 215 billion tons could last for centuries. But the need and supply don't mesh. Some 90% of utility coal use is east of the Mississippi. The biggest and most easily mined reserves lie in Colorado, Utah and Wyoming. Freight costs from there to Midwestern utilities would be twice the current charges for shipment from Midwestern mines.

Low-sulphur reserves in the Eastern coal states amount to an ample 82 billion tons or 38% of the total bituminous low-sulphur reserves. Coal men, however, say the best Eastern deposits are owned or controlled by steel producers for their own use and the rest lies in thin, hard-to-mine seams. "There isn't enough left to make a real

dent in the utility market," says John Corcoran, president of Consolidation Coal Co., a subsidiary of Continental Oil Co. Says another coal man: "When you're talking thin seams, you're doubling the cost."

Another problem is the health of the coal industry. Demand is strong now, but a sizable portion of the industry—the hundreds of small and medium-sized operators—would be endangered by wholesale switches from medium and high-sulphur coals. These smaller firms probably would go out of business, industry observers say. Even big operators would be hard pressed to finance the heavy capital investment involved in constructing new mines. Some already are asking customers to help finance mine construction.

For this reason, coal industry spokesmen are urging utilities to invest in sulphur-dioxide removal systems. At the same time, coal executives are urging regulatory agencies to go slow on enforcing strict pollution-control rules.

Even if low-sulphur coal is to be mined, it will be costly. Coal men are estimating prices as high as 40 cents per million BTUs, compared with 21 cents to 26 cents for high-sulphur coal now being burned. (BTU, for British thermal unit, is a measure of heat. Coal and other fuels usually are priced according to heat content, not according to tons or barrels).

Utilities might well be willing to pay such prices, of course. Utilities in the Great Lakes are paying 45 cents per million BTUs for imported low-sulphur fuel oil and as much as 60 cents for domestic oil. But in the long run, coal at such prices probably would cease to be competitive with nuclear power, currently rated at 28 cents to 30 cents per million BTUs, and with imported fuel oil if import rules are eased as some utilities are seeking.

Also, coal men say a good many coal-fired plants couldn't switch to low-sulphur coals without costly changes. One industry spokesman estimates 85% of the coal plants in New Jersey, for example, "couldn't use it without major furnace revisions." The reason is that most coal-fired plants are designed to burn a certain

type of coal, often from a particular region of the coal-fields. (The New Jersey plants burn coal from the Fairmont, W. Va., area.)

Long-range developments could alter the picture greatly. The Western coals, for example, won't always be inaccessible. Several Midwest utilities are starting to buy in Wyoming, hauling the coal in multicar, fast-loading "unit trains," which cut freight costs substantially.

Another possibility is shipping the electricity instead of the coal. Utilities would build steam plants at the Western mines, and then use extra-high-voltage transmission cables to send electricity to users. Use of this technique is considered imminent, both out West and in the more remote sections of the Eastern coal-fields. Presently, the cost of extra-high-voltage transmission is quite high.

Also, some utilities are starting to build plants designed to use the plentiful lignite and subbituminous coals.

MS ~~3905~~

DEFENDANT'S EXHIBIT 236

PEABODY COAL COMPANY
GENERAL OFFICES · 301 NORTH MEMORIAL DRIVE
ST. LOUIS, MISSOURI 63102
TELEPHONE GENEVA 6-3400

MARVIN O. YOUNG
VICE PRESIDENT AND GENERAL COUNSEL

April 1, 1970

Mr. Reuben Hedlund
Kirkland, Ellis, Hodson,
Chaffetz & Masters
Prudential Plaza
Chicago, Illinois 60601

RE: United States v. General Dynamics Corporation et al., Civil Action No. 67 C 1632 (N.D.Ill.)

Dear Mr. Hedlund:

Pursuant to your telephone request of today concerning certain coal reserves owned by Peabody in McDonough, Schuyler, Adams, Brown and Hancock Counties, Illinois, I would like to advise you as follows:

Peabody acquired some coal reserves in these counties during the period 1958 through 1960 by way of leases. The leases on coal reserves in Brown County, Illinois have been dropped.

Since the early part of 1961 Peabody has not attempted to acquire any further coal reserves in these Counties and has no plans at the present time to develop any of these reserves because the tonnage involved is so small that it would be economically impossible to mine such reserves.

Very truly yours,

Marvin O. Young

Marvin O. Young

MOY:nlh

FRACTION OF TOTAL ILLINOIS PRODUCTION
OF LEADING COMPANIES OTHER THAN
PEABODY* (Percentages)

Year	Freeman	2-4	2-6	2-8	2-10
1957	14.8	31.5	44.9	55.1	61.0
1958	15.7	33.8	48.4	59.1	65.2
1959	23.2	42.0	54.7	63.5	68.1
1960	24.1	42.6	55.6	64.1	68.2
1961	24.4	42.0	54.7	63.7	67.8
1962	24.2	42.4	56.5	65.5	70.1
1963	22.9	41.2	53.4	60.1	63.2
1964	23.4	42.1	53.6	61.1	64.5
1965	21.6	39.9	54.0	62.7	65.7
1966	21.4	43.0	57.8	65.5	66.7[1]
1967	21.8	44.1	57.8	65.4	66.9

* Assumes CWF was part of Freeman in 1957 and subsequently and that UEC and Freeman were merged from 1959 on.

1. Assumes 10th largest producer had 300,000 tons production.

Source: Government Exhibits 62 through 72

AVERAGE PRODUCTION, PER COMPANY*
(ILLINOIS PRODUCTION OF ILLINOIS PRODUCERS)
(000 Tons)

Year	Leading Companies[1]	Non-Leading Companies
1954	1500	25
1957	2600	23
1958	2450	18
1959	2900	18
1960	2900	24
1961	2900	25
1962	3300	31
1963	3500	38
1964	4400	38
1965	4050	34
1966	6800	55
1967	6350	44

* Assumes CWF was part of Freeman in 1957 and subsequently and that UEC and Freeman were merged from 1959 on.

1. Nearest 50,000 Tons.

Source: Government Exhibits 12, 62 through 72.

CHANGES IN CONCENTRATION IN ILLINOIS

COAL PRODUCTION SINCE 1959

-TWO MEASURES-

	Production of Top 2		Production of Top 4		Production of Top 10	
	Govt.	Adj.*	Govt.	Adj.*	Govt.	Adj.*
1959	36.2	44.3	55.0	63.1	87.2	89.3
1960	35.5	44.7	55.5	63.1	86.7	88.8
1961	36.2	46.0	55.9	63.5	87.3	89.3
1962	35.8	45.9	56.3	64.1	89.6	91.8
1963	42.7	52.2	62.5	70.5	91.3	92.5
1964	42.9	53.5	64.0	72.3	93.5	94.7
1965	41.8	51.0	60.4	69.2	94.4	95.1
1966	42.8	52.0	64.4	73.6	96.8	97.3[1]
1967	52.9	52.9	75.2	75.2	98.0	98.0
Change 59-67	+16.7	+8.6	+20.2	+12.1	+10.8	+ 8.7
Change due to Peabody	+10.0	+10.0	+10.0	+10.0	+10.0	+10.0
Change due to others	+ 6.7	- 1.4	+10.2	+ 2.1	+ 0.8	- 1.3

*Adjustment consists of recognizing Freeman-UEC as merged effective 1959 instead of 1967.

[1]Assumes 10th largest had 300,000 tons production.

Source: Government Exhibits 62 through 73

CHANGES IN CONCENTRATION IN ILLINOIS, INDIANA AND WESTERN KENTUCKY SINCE 1959

-TWO MEASURES-

	Production of Top 2		Production of Top 4		Production of Top 10	
	Govt.	Adj.*	Govt.	Adj.*	Govt.	Adj.*
1959	33.1	37.9	46.6	51.5	71.9	73.9
1960	33.4	38.5	46.5	51.7	71.5	73.6
1961	34.4	39.8	47.2	52.6	72.0	74.4
1962	35.4	40.4	48.1	53.1	75.7	78.3
1963	41.5	46.3	53.7	58.6	78.2	80.4
1964	43.4	47.7	55.3	60.6	81.0	83.2
1965	42.6	46.4	55.8	60.5	85.2	87.5
1966	44.1	47.7	57.6	62.0	88.9	91.2
1967	48.6	48.6	62.9	62.9	91.4	91.4
59-67	+15.5	+10.7	+16.3	+11.4	+19.5	+17.5
:a- body [Peabody]	+12.2	+12.2	+12.2	+12.2	+12.2	+12.2
Rest	+ 3.3	- 1.5	+ 4.1	- 0.8	+ 7.3	+ 5.3

*Adjustment consists in recognizing Freeman-UEC as merged effective 1959 instead of 1967.

Source: Government Exhibits 77 through 85

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CALL LETTERS FBJ DLPD 3/5/70 CHARGE TO National Coal Association
Washington, D. C.

DEFENDANT'S EXHIBIT 238

The President
The White House
Washington, D. C.

Page 1 of 3 pages

The Wall Street Journal of today (article by Burt Schorr, page 14) reports that the Oil Import Board of Appeals has decided to open the Midwest to foreign residual oil. If so, this Nation is threatened with dire future consequences. We can have both clean air and reliable electricity, only by using domestic coal with techniques now available for the removal of sulphur dioxide from stack gas. The manufacturers of sulphur removal equipment will guarantee performance, and indications are that the cost will be no greater

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CALL LETTERS FBJ DLPD CHARGE TO

The President Page 2 of 3 pages

than the cost of using foreign oil.

Unfortunately, the electric utilities are more inclined to comply with clean air regulations by switching to foreign oil. If they are permitted to do this, the domestic coal industry will suffer. But far more important, the entire national security will be endangered, because it will lead eventually to very heavy dependence on energy sources which are unreliable because of problems in Mid-East and other sources and because of possible interruptions in transportation over great distances. In addition, the government will be afflicted with a serious drain on our balance of

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CALL LETTERS FBJ DLPD CHARGE TO

The President Page 3 of 3 pages

payments.

The Nation can and should have clean air and reliable energy. We hope you will do whatever you can to see that the utilities build sulphur removal facilities which will permit use of our most abundant energy source rather than switch to foreign oil. To this end, existing limitations on foreign oil imports to the Midwest should be retained.

Stephen Dunn, President

~~1931~~ #21

DEFENDANT'S EXHIBIT 239

PROPOSED PLANS OF COMPLIANCE WITH CHICAGO AIR POLLUTION CONTROL ORDINANCE OF THOSE FACILITIES FOR WHICH A RESPONSE TO COURT-ORDERED SUBPOENA QUESTIONNAIRE WAS RECEIVED

There are forty facilities [excluding Commonwealth Edison generating stations] which are located within the Metropolitan Chicago Interstate Air Quality Control Region, as designated 42 C.F.R. §81.14, and for which a response to the Court-Ordered Subpoena Questionnaire was received. [See Table D-P of Defendants' Exhibit No. 55].

Of these forty facilities, the following ten are located inside the City of Chicago:

	Company & Facility		1967 Total Coal Consumed 1/
1.	Campbell Soup		Less than 20,000 tons
2.	Celotex Corporation		22,000 tons
3.	Central Soya-Chemurgy Division		65,000 tons
4.	Container Corporation	- Water Street	23,000 tons
5.	Container Corporation	- Ogden Avenue	20,000 tons
6.	Darling, Inc.	- Ashland Avenue	34,000 tons
7.	Darling, Inc.	- West 46th Street	60,000 tons
8.	Interlake Steel	- Torrance Avenue	395,000 tons
9.	International Harvester	- Wisconsin Steel Division	25,000 tons
10.	International Harvester	- Tractor Division	21,000 tons
11.	Proctor & Gamble		60,000 tons
12.	Sherwin Williams		23,000 tons
13.	Swift & Company		28,000 tons

TOTAL: 10 companies; 13 facilities; over 776,000 tons of coal

The above facilities are subject to Section 17-25(3)(a) of the Municipal Code of Chicago, as amended by Ordinance of June 23, 1969 [Journal of the City Council, pp. 5618-5619] 2/ and are subject to the jurisdiction of the Chicago Department of Environmental Control.

1/ Source: The respective Form 150 responses of the companies set forth above.

2/ An excerpt of this provision is attached hereto as an Appendix.

That agency sent out a questionnaire in October of 1969 to the approximately 2,500 industrial facilities in Chicago which burn fuel (oil, gas or coal) at a rate of 288,000 BTU per hour on an annual average. The purpose of this inquiry was to obtain from the recipients the manner or plan of compliance with §17-25(3)(a) proposed for these facilities.

As a follow-up to the Court-Ordered Subpoena Questionnaire, the following is a summary of the responses to the Department of Environmental Control inquiry <u>for those facilities for which a subpoena response was also received</u>.

Group I. <u>Two</u> of the above facilities burn low sulphur Southern Illinois metallurgical coal for the purpose of coking. This coal has a sulphur content of less than 1.3% and falls well below the Ordinance requirement.
1967 tonnage represented: 420,000 tons.

Group II. Of the remaining 11 facilities, <u>2</u> did not respond to the Department of Environmental Control inquiry.
1967 tonnage represented: 50,000 tons.

Group III. Of the remaining 9 facilities:

A. <u>6</u> facilities have converted, or will convert during the year 1970, all coal-burning boilers to use gas, low sulphur #6 oil or a combination of both.
1967 tonnage represented: 179,000 tons.

(1) 1 of these 6 has converted to natural gas/low sulphur oil but may need to burn a small amount of low sulphur (less than 2.5%) coal for emergency use.

(2) 4 of these 6 have converted coal-burning units to oil and gas units and are burning no coal whatsoever.

(3) 1 of these 6 is burning natural gas on an interruptible basis until mid-1970, at which time it will have converted its combustion units to the use of #6 (low sulphur) oil.

B. 2 facilities will continue to burn coal in the boilers but will burn coal of less than 2.5% sulphur content.
1967 tonnage represented: 81,000 tons.

C. 1 of the above group will convert to the equal use of gas and oil by October of 1970. After such conversion, this facility also intends to continue to burn high sulphur coal in a quantity which is one-third its present coal consumption rate.
1967 tonnage represented: 65,000 tons.

The respondent for this facility stated that two coal suppliers had informed it that there would ~~be~~ not be available to the respondent coal with a sulfur content of less than 2.5%.

~~593~~
#24

Price [illegible] per copy

D. C. McGRAW, JR., Publisher
The Mining Papers
—Coal Age—Engineering & Mining Journal—E & M J Metal & Mineral Markets
—Keystone Coal Buyers Manual—Coal Mine Directory—Monthly News Bulletin Service

JOSEPH E. FORSYTHE, General Manager

GEORGE F. N[illegible], Assistant General Manager

FRANK L. VOSKOVITCH, Assistant Editor

Keystone Coal Buyers Manual
Coal Mine Directory
Monthly News Bulletin Service

[illegible] CO., INC.
330 W[illegible] 36, N. Y.

All coal producing counties in the State of Illinois are included in Bituminous Coal Producers District No. 10.

Source: Illinois Dept. of Mines & Minerals
Statistics For State Calendar Year 1959
Total Tonnage: 45,371,626
Strip Tonnage: 29,532,328
No. of Mines: 139
Total Employees: 10,827

Source: United States Bureau of Mines
1959 Total Tonnage: 45,165,616
1959 Strip Tonnage: 31,911,987
Sizes of Mines—1959
500,000 Tons & Over—39
200,000 To 500,000—9
100,000 To 200,000—6
50,000 To 100,000—11
Less than 50,000—72

Railroads Serving: AT&SF; B&O; CB&Q; C&EI; C&IM; C&NW; CRI&P; G&GE; GM&O; IC; L&N; M&St.L; MoPac; NYC; PRR; SL&OF; TP&W.

Alphabetical Directory of Coal Operating Companies and Mines that produced 50,000 tons or over annually and some smaller mines whose tonnage moves by rail or water into important competitive markets.

Addresses of officials are the same as the company or the office or mine address under which the name appears, unless a separate address immediately follows the name.

Detailed data submitted by Operators was gathered in December 1960; January, February & March 1961.

There are 34 Companies and 52 Mines listed herein.

BELL & ZOLLER COAL CO.
208 So. LaSalle St.
Chicago 4, Ill.
(Operates also in Dist. 9)
(Aff. with Zeigler Coal & Coke Co., Dist. 10)
Chm. Bd. .... Alfred M. Zoeger
Pres. .... Stuart Colson
Exec. Vice Pres. .... W. F. Landon
Vice Pres. & Treas. .. C. W. Peterson
Sec. .... J. O. Hare
Vice Pres. Sales
Warren F. Wardberg
Vice Pres. Sales Prom.
Willard Watrin
Vice Pres. Lake Sales .. J. M. Rogers
Asst. to Pres. .... H. F. McDonald
Asst. to Pres. .... M. E. Walsh
Asst. to Exec. Vice Pres.
R. C. Rasmussen
Secy. Rate
J. W. Morris, D. I. Allen
Operating Office—Johnston City, Ill.
Vice Pres. (Opr.) .... Roland Wilson
Asst. to Vice Pres. (Opr.)
R. P. Wilson
Prep. Engr. .... Wesley Smith
Maint. Engr. .... Arthur Towle
Safety Inspec. .... Coy Smith
Pur. Agt. .... J. C. Davis
Div. Engr. .... Gilbert Engram
Gen. Washer Supt. .... Wm. McNeil
Gen. Agents: Bell & Zoller Coal Co.
1960 Illinois Production: 4,394,214

Zeigler No. 2 Mine
P. O. .... Zeigler, Franklin Co., Ill.
Sh. Pt.
Zeigler Mine, IC, CBQ, MoPac
Rds.
Supt. .... Edmund Orasick
Mine Mgr. .... Floyd Barrett
Supply Clerk .... Ivan Thomas
Chem. .... Ray Crane
Prep. Mgr. .... Ray Cavney
[illegible]
Daily Cap. (Cleaned Coal) (2 Shifts) .... 5000 T.
Sizes Washed: 7" x 0
[illegible]
Tonnage Cleaned, 1960 .... 1,073,[illegible]
Trade Name: Zeigler Superwashed
Mng. Equip.: 7 AT Mng. Machs; 7 Mbl. Ldg. Machs; 7 Mbl. Drills; 3 Rock Dust.; 7 Units Roof Bolt; 43 Pumps
Haulage Equip.: 70 Steel M. Cars 12 Tr. Locos: 42" T.G.; 14 Shuttle Cars; Mother Belt
Power Purchased: D.V. 250 D.C. Trans. 440 A.C.
Prep. Owned: [illegible]
Employees [illegible]
Cap. 5000 T.
1960 Tonnage, 1,073,147

Zeigler No. 4 Mine
P. O. .... Johnston City, Williamson Co., Ill.
Shp. .... Zeigler Mine, IC, MP & CB & Q & C & EI Rds.
Supt. .... Dealas Pierce
Mine Mgr. .... Raymond Gothard
Supply Clerk .... John [illegible]
Exam. .... Charles Crossman
Seam: No. 6 84" Th.
Prep. Mgr. .... Courtney Birkelbach
Designer of Plant: McNally-Pittsburg Mfg. Co.
Prep. Equip.: McNally-Pitt. Washer; Deister Tbls.; Thermal Driers; [illegible] Vib. Scrns.; Crusher; Ldg. Bms.; Mineral Oil Dust Treat.; Calcium Freeze Proof
Daily Cap. (Cleaned Coal) (2 Shifts) .... 4000 T.
Sizes Washed: 7 x 0
Sizes Dried: 1 x 0
Sizes Shipped: 7" x 3"; 3" x 2"; 2" x 1½"; 1½" x 1"; 1½" x ¾"; 1" x ¾"; 1½" x 10M; ¾" x 10M; ¾" x 0
Tonnage Cleaned, 1960 1,070,843
Trade Name: Zeigler Superwashed
Mng. Equip.: 6 Mbl. Coal Drills; 6 RT Cutting Machs; 6 Mbl. Ldrs.; 4 Cont. Miners; Rock Dust.; 2 Units Roof Bolt; 6 Pumps
Haulage Equip.: Conveyors; 3 Tr. Locos; 16 Shuttle Cars; 87 Steel M. Cars; T.G. 42"
Power Purchased: [illegible] D.V. 250 D.C. [illegible] A.C.
Prep. Owned: Life Exps. 20 yrs.; 276 Employees; 2 shifts
1960 Tonnage, 1,074,043

[illegible] Mine
P. O. .... [illegible]
[illegible]
Prep. Equip.: [illegible]
[illegible] Washers; [illegible]
Treat.: Calcium Freeze Proof; [illegible]
Tbls.; Ldg. Bms.

Daily Cap. (Cleaned Coal) (2 Shifts) .... 2000 T.
Sizes Washed: 6 x 0
Sizes Shipped: Over 6", over 3", 6 x 1½, 3 x 1½, 1½ x 0; 1 x ¾; 1½ x ¾
Tonnage Cleaned, 1960 .... 343,[illegible]
Trade Name: Midwest Superwashed
Mng. Equip.: 2 Cut. Machs.; 4 Ldrs.; 3 Drills
Haulage Equip.: 42" T.G.; 3 Shuttle Cars; Conveyors
Power Pur., 250 D.C., 440 A.C.
Prep. Owned: Life Exps. 47 yrs.; Employees 93; 2 shifts; Daily Cap. 2000 T.
1960 Tonnage, 343,[illegible]
For additional data, see page 453

BELLE VALLEY COAL CO.
R.D. 1, Belleville, Ill.
Pres. & Gen. Mgr. .... C. O. [illegible]
Chief Engr. .... E. W. Fleet
Sales Agts.:
Schlafly & Associates

Belle Valley Mine
P.O. .... Belleville, L.O.B. Ill.
Supt. .... Kenneth Wall
Exam. .... Roland Fish
Chief Clerk .... C. E. Deutch
Top Foreman .... Edward Williamson
Seam: No. 6 Seam; 84" Th.
Prep. Mgr. .... Harry [illegible]
Designer of Plant: Wemco
Prep. Equip.: WEMCO Heavy Media Washery; Crusher; Screens
Daily Cap. (Cleaned Coal) .... 600 T.
Sizes: 4 x 0; 3 x ¾; 1½ x ¾; ¾ x 3/16
Equip.: Ldg. Machs; 4 Tr. Locos T.G. 42"; [illegible] ton steel cars
Power Pur.: D.V. 250 D.C.
Employees 42; 2 shifts; Life Exps. 15 yrs.; Daily Cap. 800 T.
1960 Tonnage, 78,440

BIG TEN COAL CO.
2106 N. Meridian St.,
Indianapolis, Ind.
[illegible]
[illegible]
[illegible] Co.

Bryant Mine
P.O. .... Lewistown, Fulton Co., Ill.
Shp. .... St. David, CB&Q Rd.
Supt. .... Otis [illegible]
Seam: No. 5 seam; 60" Th.
Prep. Mgr. .... Ben Clifford
Designer of Plant: Daniels Co.
Prep. Equip.: Pri. Tbl.; Daniels Heavy Media Washer; Vib. Scrns.; Crshrs.; Ldg. Bms.; Vibrex Rd.; Oil Dust. Treat.; Sodium Chloride Type Freeze-Proof Treat.; Bird Humboldt Dryer
Daily Cap. (Cleaned Coal) (1 Shift) .... 1700 T.
Sizes Under 6" x 4" Egg; 1½" x 10 M. Scrngs.; ¾" x ½" Stkr.
Tonnage Cleaned, 1960 143,427
Mng. Equip.: 1 Drag.; 1 Ldg. Shvl.; 1 Crhsr., Drill
Haulage Equip.: 8 Euclid Trailer Trucks
Power Pur.: 440 A.C. 200 KVA
Prep. Leased: Life Expec. 4 yrs.; Employ. 27; Daily Cap. 1200 T.
1960 Tonnage, 143,427
For additional data, see page 457

BLUE BIRD COAL CO.
224 So. Michigan Ave.,
Chicago, Ill.
Chm. Bd. .... T. E. Cochran
Pres. .... Richard E. Cochran
Sales Agt. .. Zeigler Coal & Coke Co.

Blue Bird No. 2 Mine
P. O. .... Harrisburg, Saline Co., Ill.
Shp. .... Harrisburg, NYC Rd.
Pur. Agt. .... M. [illegible]
Seam: No. 5 Seam; 64" Th.
Prep. Equip.: Deister Tbls.; Crshrs.; Vib. & Shkr. Scrns.; Pck. Tbls.; Ldg. Bms.
Sizes Washed: 1½ x 10M; 1" x 10M; ¾ x 10M
Sizes Dried: ¾" x 0"
1960 Tonnage, [illegible]

[illegible] Co.
(1960 Tonnage, [illegible])

Daily Cap. (Cleaned Coal) (1 shift) 1600 T
Size Washed: 3 x 0
Sizes Made: 7 x 4 Lump; 4 x 2; 2 x 1¼; 1¼ x 0; ¾ x 0; ⅝ x 3/16; 3/16 x 0
Tonnage Cleaned, 1960 106,312
Trade Name: Heat Wave
Mng. Equip.: 2 Draglines; 2 Ldg. Shovels
Haulage Equip.: 8 Trucks
Power pur.: D.V. 220-440 A.C.
Prop. Leased: Life expectancy 4 yrs.; Employees 30; 1 shift; 700 T. daily
1960 Tonnage, 106,312

For additional data, see page 487

MT. OLIVE & STAUNTON COAL CO.

1720 Arcade Bldg., St. Louis 1, Mo.
Pres. .... J. Louis Zelber
V. Pres. .... John S. Forman
Sales Agt., Republic Coal & Coke Co.

Staunton No. 2 Mine

Loc. .... Madison Co., Ill.
P. O. .. Staunton, Macoupin Co., Ill.
Ship. .... Staunton, C & N Ry.
Mine Supt. .... George Timmerman
Mng. Engr. .... Byron O'Neill
Mine Mgr. .... Steve Pirek
Shaft: No. 6; 78" Th.
Employees 230; Daily Cap. 3100 T.
Track Gage .... 42 in.
Type Mechanical Loader .... Mobile
Designer of Plant: Jeffrey Mfg. Co.
Preparation Plant .... Baum Jig
Daily Cap. (Cleaned Coal) .... 3600 T
Sizes Washed: 6" x 6"; 6" x 3"; 6" x 3"; 3" x 3"; 3" x 1¼"; 1¼" x ¾"; ¾" x 5/16"
Power pur. & gen.: D.V. 230 D.C.
Note: Temp. Idle

For additional data, see pages 467, 487

NEW OAK HILL COAL CO.

Box 411, Harrisburg, Ill.
Gen. Supt. .... Roger Knickerbocker

No. 4 Mine

Loc. ...... Harrisburg, Saline Co., Ill.
Ship. .... Via N.Y.C. RR.
Strip: No. 5 seam; 60" Th.
1960 Tonnage, 94,580

OLD BEN COAL CORP.

300 West Jackson Blvd., Chicago 6, Ill.
[Wholly Owned Subsidiary, Coal Processing Corp. (Va.)]
Chm. of Bd. .... D. W. Buchanan
Pres. .... D. W. Buchanan, Jr.
Sec. .... Otto J. Gibson
Asst. to Pres. ..... Wm. C. Campbell
Vice Pres. Sls. .... B. B. Starck
Treas. .... E. O. Dunford
Comp. .... T. L. Estrup

Operating Office: Benton, Ill.

Vice Pres. (Opr.) .. Geo. A. Hirstock
Vice Pres. (Engr.) J. W. MacDonald
Asst. to V.P. Oper. ..... E. T. Moroni
Mgr. Ind. Engrng. .... John James
Chf. Elec. Engr. .... Rollie Pierce
Prep. Engr. .... A. J. Webster
Div. Pur. Agt. .... R. T. Golding
Safety Inspec. .... B. Barnelski
M. Mech. .... E. Karrell
Sales Agt., Old Ben Coal Corp.

Old Ben No. 9 Mine

P. O. .. West Frankfort, Franklin Co., Ill.
Ship. .. CB&Q; IC; MoPac; C&E; Ills.
Supt. .... O. D. McDaniel
Mine Mgrs. .... Wm. Beck; E. C. Harris
Mine Elec. .... Nick Kovaleski; John Tevlow
Top Foreman .... L. T. Green; Leon Martin
Shaft: No. 6 seam; 106" Th.
Designer of Plant: Old Ben Coal Corp.
Prep. Equip.: Jig & Heavy Media Washer; Coal Air Cleaners; Crshrs.; Vib. Dehy. Scrns.; Ldg. Bms.; Freeze-Proof; Oil Treat.
Daily Cap. (Cleaned Coal) (2 shifts) 10,000 T
Sizes Washed: 6 x 28 M
Sizes Air Cleaned: ¼ x 28M
[illegible] ¼ x 28M; ¾ x ¼
Other Sizes: 6 x 3; 3 x 2; 2 x 1¼; 1¼" x ¾; 1¼" x ¾; ¾ x ¾; ¾ x 28M; ¾ x 0; 10M x 0; ¾ x 28M; ¾ x 10M; 2 x 28M; 1 x 28M

Tonnage Cleaned, 1960 1,636,630
Mng. Equip.: Cont. Miners
Haulage Equip.: Steel M. Cars; Tr. Locos.; Shuttle Cars; 42" T.G.; Panel Convyrs.
Power Pur.: 6300 KVA; D.V. Mine 275 D.C., Tipple 220 A.C.
Prop. Owned: Life Expec. 25 yrs.; Employees 433; 2 shifts; Daily Cap. 10,000 T.
1960 Tonnage, 1,972,640

Old Ben No. 14 Mine

(Closed 6/25/60)
(1960 Tonnage, 275,180)

Old Ben No. 22 Mine

(Closed 2/1/60)
(1960 Tonnage, 36,730)

Old Ben No. 21 Mine

P. O. ...... Sesser, Franklin Co., Ill.
Ship. ..... Sesser, CB & Q, IC, MP & C & EI RR's
Supt. .... Isham James
Mine Mgrs. .... Dennis Presley; Ford Bain; Robt. Littlefair
Mine Elec. .... J. W. McGregor
Top Fore. .... Reuben Flath
Shaft: No. 6; Seam, 106" Th.
Prep. Equip.: Jig & Air Tbls.
Sizes Washed: 6" x 0
Mng. Equip.: Cont. Miners
Haulage Equip.: Shuttle Cars & Belts
Prop. Owned: Daily Cap. 12,000 T.; 3 shifts
1960 Tonnage, 1,313,047

For additional data, see pages 333, 488

PEABODY COAL CO.

301 Olive Street, St. Louis 2, Mo.
Chm. Bd. .... F. Stillman Elfred
Pres. .... Merl C. Kelce
Exec. Vice Pres. ...... Ted L. Kelce
Vice President .... S. L. Jewell
Vice President .... Roy O. Park
Vice President, Finance
R. J. Snider
Vice Pres. & Sec. James W. Taylor
Controller & Asst. Treasurer
E. H. Buckley
Treas. .... S. Kimmerly
Vice President & Dir. of Engr.
C. P. Arnold
Vice President, Strip Operations
Don Johnston
Vice President, Underground Operations .... E. C. McCollum
Chf. Engr. .... E. R. Phelps
Preparation Superintendent
A. P. Massmann
Gen. Supt. Ill. Mines
James McDowell
Sls. Agts., Peabody Coal Co.

No. 10 Mine

P. O. ...... Pawnee, Christian Co., Ill.
Ship. .... Ills. C & [illegible]
Mine Supt. .... Leo [illegible]
Slope: No. 6 seam; 84" Thick
Prep. Mgr. .... Tom Rhodes
Designer of Plant: Roberts & Schaefer
Prep. Equip.: R&S Jig Washer; Dehy. Scrns.; Ldg. Bms.; Oil Type Dust. Treat.
Daily Cap. (Cleaned Coal) (2 shifts) 12,000 T
Sizes Washed: 6 x 2
Sizes Shipped: 6 x 2; 2 x 2; 1¼ x 0; ¾ x 28M; 6 x 0; 6 x 2; 2 x 0 Raw
Trade Name: Dynamo
Mng. Equip.: 8 Mng. Machs.; 4 Mbl. Ldrs.
Haulage Equip.: Belts; Shuttle Cars
Power Pur.: 22,000 A.C.
Planned Daily Cap. 12,000 T.
1960 Tonnage, 4,117,832

Midwest Mine

Sls. Agt., St. Louis Coal Sales, Inc.
P. O. Millstadt, St. Clair Co., Ill.
Ship. .... Via Truck
Strip: Ill. No. 6 seam; [illegible] Th.
Supt. .... Fred Schrader
Asst. Supt. .... [illegible]
Prep. Equip.: Baum Jig Washer; Drier; Oil Dust. Treat.; Consol. Ldg. Bms.
Daily Cap. (Cleaned Coal) .. 3200 T.
Trade Name: Midwest Belleville Coal
Major Use Value: Steam
Sizes Washed: 6" x 0
Sizes Dried: ¾" x 0
Sizes Shipped: [illegible] x 4; 4 x 2; ¾ x ¾; 1¾ x [illegible] ¾ x ¾; ¾ x 0
Mng. Equip.: 1 Strip. Sh.; 1 Ldg. Shvl.; 2 Draglines; 2 Drills; 3 Dozers
Haulage Equip.: 6 Tract.-Trail. Units

Power Pur.: 500 KVA; C.V. 4000 A.C., Tipple 4000 A.C.
Prop. Owned & Leased: Daily Cap. 3000 T.
1960 Tonnage Before Acquis., 192,163
1960 Tonnage, 673,720

St. Ellen Mine

(Closed 3/60)
(1960 Tonnage, 476,408)

Energy Mine

Sls. Agts., Peabody Coal Co.; Reliable Coal & Mining Co.
Loc. .... Herrin, Williamson Co.
Ship. Herrin, CB&Q; IC; MP RR.
Supt. .... Otis D. English
Prep. Equip.: McNally Washery; Oil Treatment; Drier; Calcium Freeze Proof
Daily Cap. (Cleaned Coal) (1 shift) .. 2500 T
Sizes Washed: 6 x 0
Sizes Dried: ¾" x 0
Sizes Shipped: 6 x 4; 4 x 2; 2 x 1¼; 1¼ x ¾; ¾ x 10; 3/16 x 0; 1¼ x 0
Trade Name: Energy
Mining Equip.: 2 Ovbdn. Drills; 2 Ldg. Shvls.; 2 Drags.
Haulage Equip.: 1 Truck; 6 semi-trails.; 6 Trucks
Power Pur.: 4160, 440 A.C.
Prop. Owned: Life Expec. 10 yrs.; 1 shift; 2800 T.P.D.
1960 Tonnage, 337,414

Wilmington Mine

P. O. Wilmington, Will & Kankakee Counties, Ill.
Ship. ...... Mullins; SF&GMO RR's
Supt. .... Sanders Payne
Asst. Supt. .... J. Forman
Strip: Wilmington #2; 36" Thick
Designer of Plant: McNally-Pittsburgh Mfg. Co.
Prep. Equip.: Washer; Drier; Dust. Treat.; Scrns.; Ldg. Bms.; Salt Type Freeze-Proof Treat.
Daily Cap. (Cleaned Coal) ... 4800 T
Sizes Washed: 3" x 6"
Sizes Dried: 1 x 0
Sizes Shipped: 6 x 3, 3 x 1, 1 x ¾, 1 x 0, ¾ x 0, 1¾ x 1, 3 x 1¾
Trade Name: Wilmington
Mng. Equip.: 2 stripping shovels, 5 draglines, 4 loading shovels, 3 overburden drills, 10 trucks, 4 gas-electric locomotives, 3 steam locomotives, 6 tractors, T.G. 56"
Power Pur.: D.V., 4000 A.C.
Prop. Owned: Employees, 300; 1 shift; Daily Cap. 4800 T.
1960 Tonnage, 689,917

Seminole Mine

(Closed 1960)
(1960 Tonnage, 320,761)

Kay Mine

Loc. ...... Beardstown, Cass Co., Ill.
Ship. .... Via River Barge Ldg. & C.B.Q. RR.
Supt. .... C. W. Daley
Strip
Prep. Equip.: Washery, Dryer, Crshr.; Dehy. Scrns.; Ldg. Bms.; Pckg. Tbls.; Salt Type Freeze-Proof Treat.
Daily Cap. (Cleaned Coal) (1 Shift) .... 2000 T.
Sizes Washed: 6" x 0
Sizes Dried: 1¼" x ¾ MM.
Trade Name: Kay
Equip.: Dragline; Ldg. Shovel; Semi-Trailers
Property Owned
1960 Tonnage, 347,746

River King Mine

Sls. Agts., Peabody Coal Co.; St. Louis Coal Sales, Inc.
P. O. Box A, Freeburg, St. Clair Co., Ill.
Ship. .... Freeburg; IC RR. Dock Ldg., Mississippi River at E. St. Louis
Strip: No. 6 Seam
Prep. Equip.: New McNally-Pitt. Clean. Pl. Wash. Cap. 1,600 T.P.H.; Heat Dryers
Sizes Washed: 1¼" x 28 M; 1" x ¾"; 1" x 28M; 3" x 1" Crsh.; 1¼" x 28M
Mng. Equip.: 70 yd. Shvl.
Haulage Equip.: 3 Trks.
1960 Tonnage, 3,166,917

For additional data, see pages 333, 411, 471, 488, 512

PIONEER COLLIERIES CO.

Laura, Ill.
Pres. .... P. E. Perkins
Vice Pres. .... C. O. [illegible]
Sales Mgr. .... H. C. Moore

Pioneer No. 1 Mine

P. O. .... Laura, Peoria Co., Ill.
Ship. .... Laura; [illegible] Truck
Mine Supt. .... C. O. [illegible]
Strip: Ill. No. 6 Seam; 42" Th.
Prep. Equip.: O.R.C. Jig
Sizes Washed: 3¼" x 0
Sizes Shpd.: 3¼" x 1"; 1" x ¾"; ¾" x ¼M; ¾" x ¼M
Mng. Equip.: 1 Ldg. Shvl.
Haulage Equip.: 3 Trucks
Power Pur.: 4150 A.C.
Prop. Leased: Life Expec. 17 yrs.; Employees 30; 1 shift; Daily Cap. 800 T.
1960 Tonnage, 144,645

PSCHIRRER COAL CO.

R.R. No. 4, Canton, Ill.
Pres. .... Geo. Pschirrer
V. Pres. .... Ray Pschirrer
Sec.-Treas. .... A. R. Pschirrer

No. 6 Mine

P. O. ...... Canton, Fulton Co., Ill.
Ship. ...... Harris, CB & Q RR.
Mine Elect. .... Ernest Pschirrer
Prep. Mgr. .... Ray Pschirrer
Shaft: No. 6; 52" Th.
Prep. Equip.: R&S Air Cleaner; Vib. Dust. Treat.; Mrnts.; Scrns.; Pck. Tbls.; Ldg. Bms.
Sizes Air Cleaned: 1" x 0"
Mng. Equip.: Post Mtd. Drills Rock Dust.; SW Machs; Self Ldg. Convyrs.; Pumps
Haulage Equip.: Mother Belts
Power Pur.: D.V., 220 A.C., 250 D.C.; Tipple, 220 A.C.
Prop. Leased: Life Expec. 15 yrs.; Employees 28; 1 shift; Daily Cap. 300 T.
Note—New 12/59

SAHARA COAL COMPANY, Inc.

59 E. Van Buren St., Chicago 5, Ill.
Chm. Bd. & V. Pres.,
Henry C. Woods
Pres. & Treas. .... F. H. Woods
V. Pres. .... C. T. Hayden
Pur. Agt. .... R. L. Fiedler
Sec. & Asst. Treas. ... E. J. Starshak
Sales Mgr. .... Harry Ezzard
Sales Agts., Sahara Coal Co., Inc.

Mine Office at Harrisburg, Ill.

Gen. Supt. .... Paul Hallerstiben
Prep. Engr. .... Carl D. Griffith
Chf. Engr. .... Walter S. Lamm
Mech. Engr. .... Hayes Bartness
Elec. Engr. .... D. Fiala
1960 Tonnage, 1,892,274

Central Preparation Plant

P. O. .. Harrisburg, Saline Co., Ill.
Ship. .... Harrisburg, NYC RR.
Supt. .... J. A. Bottomley
Elect. .... F. Wallace
Foreman .... Jess Black
Mines Supplying Raw Coal: Sahara Nos. 5, 6 & 16
Designer of Plant: McNally-Pittsburg Mfg. Co.
Prep. Equip.: Baum Washery; Oil Dust. Treat.; Crusher; Vib. Eldr. & Bar Scrns.; Pckg. Tbls. & Ldg. Bms.; Visco Driers; Heat Drying Freeze Proof
Daily Cap. (Cleaned Coal) (2 shifts) 10,000 T
Sizes Washed: 6" x 0
Sizes Dried: 1" x 28M & Interm.
Trade Name: Sahara
Major Use Values: Domestic; Steam; Metallurgical
Sizes Shipped: 6 x 3; 3 x 2; 2 x ¾; 1¾ x 1; 1 x ¾; 1¾, 1" & ¾" x 28M; 1¾, 1 & ¾ x 10M
Life Expect. 25 yrs.; Emplys. 33
1960 Tonnage, 1,892,274

Sahara No. 5 Mine

P. O. .. Harrisburg, Saline Co., Ill.
Ship. .... Harrisburg, NYC RR.
Mine Supt. .... Charles Bard
Mine Elec. .... A. W. Lanham
Foreman .... Tom Goldman
Slope: No. 5; 36 to 60" Th.
Prepared at Central Prep. Plant
Mng. Equip.: SW Cutting Mach.; Coal Drills; Port. Rock Dust.; Pumps
Haulage Equip.: Mbl. Ldrs.; Shuttle Cars; 2 36" Belt Convyrs.; 12 Tr. Locos; 140 Steel M. Cars; 42" T.G.; 4% ml. track

1963 KEYSTONE COAL BUYERS MANUAL

A McGraw-Hill Publication

Price $35.00 per copy

McGraw-Hill Mining Publications

Coal Age—Engineering & Mining Journal—E & M J Metal & Mineral Markets
Keystone Coal Buyers Manual—Coal Mine Directory—Monthly News Bulletin Service

WILLIAM J. PARKIN, Publisher
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McGRAW-HILL PUBLISHING CO., INC.
330 West 42d St., New York 36, N. Y.

SAXTON COAL CORP.
301 Main St., Petersburg, Ind.
Pres. .... Kenneth Youngs
Vice Pres. .... Bernard Youngs
Gen. Mgr. .... Darwin Youngs
Sales Agts. Sterling-Midland Coal Co.

Walnut Grove Mine
P. O. .... Harrisburg, Saline Co., Ill.
Seam: No. 5: 48" Th.; No. 6: 48" Th.
Supt. .... Asa Hills
Fore. .... Clifford Shoulders
Chf. Elec. .... Jack Jenkins
Prep. Mgr. .... J. Vaughn
Des. of Plant: McNally-Pitt.
Prep. Equip.: Jig: McNally Cent. Driers: Bait Freeze-Proof
Sizes washed: all
Sizes dried: $\frac{3}{8}$ x 28M
Daily Cap. (Cleaned Coal) 2500
Sizes: 4 x 2; 2 x 1¼; 1¼ x 28; 1 x 28; $\frac{3}{8}$ x 28; 4 x 10; 1¼ x 10; 1 x 10; $\frac{3}{8}$ x 10
Mng. Equip.: Drills; Dozers; Drags
Haulage Equip.: Tractor-Trailer, 25T cap.
Prop. Leased: Life Expec. 30 yrs.; Employs. 94
1962 Tonnage, 686,737

For additional data, see page 429

SOUTHWESTERN ILLINOIS COAL CORP.
1814 Merchants Bank Bldg., Indianapolis, Ind.
Pres. .... Chester Jackson
V. Pres. .... T. C. Mullins, Jr.
2212 Prudential Plaza
Chicago 1, Ill.
Sec.-Treas. & Gen. Mgr. .... E. D. Berger
Sales Agt. Walter Bledsoe & Co.

Streamline Mine
P. O. Percy, Randolph Co., Ill.
Ship .... Percy, GM&O, MP RR.
Mine Supt. .... W. E. Mullins
Designer of Plant: McNally-Pittsburg Mfg. Co.
Prep. Equip.: Norton Washery
Daily Cap. (Cleaned Coal) .... 4200 T
Sizes Washed: 6" Down
Strip: No. 6: 72" Th.
Mng. Equip.: 1 stripping shovel; 2 draglines; 1 loading shovel; 1 overburden drill
Haulage Equip.: 6 Tract.-Trails.
Power Purchased
Prop. Owned: Life Expec. 10 Yrs.; Employees 118; 3 shifts; Daily Cap. 4000 T.
1962 Tonnage, 1,072,000

For additional data, see page 33

STONEFORT COAL MINING CO., INC.
2829 N. Meridian St.,
Indianapolis 8, Ind.
Pres. .... S. P. Sherwood
Vice Pres. (Oper.) William W. Dukes
Sec. & Treas. .... R. A. Baldwin

Will Scarlet Mine
Sls. Agt. Sterling-Midland Coal Co.
P. O. .... R.R. #1, Stonefort, Williamson Co., Illinois
Ship .... Stonefort, NYC
Supt. .... R. W. Edwards
Prod. Mgr. .... J. W. Moore
M. Mech. .... T. E. Davis
Strip: Davis-Dekoven, 30"
Prep. Engr. .... R. D. Yocum
Designer of Plant: Self-designed
Prep. Equip.: Baum Jigs, Crushers, Bauchman Verti-Vane Dryer, Oil Treat.; Heat Driers Freeze-proof Treat.
Daily Cap. (Cleaned Coal)(1 shift) 3200 T
Sizes Washed: 4" x 1¼"; 1¼" x $\frac{5}{8}$"; $\frac{5}{8}$" x 10 M; 1¼" x 10 M; 1¼" x $\frac{5}{8}$"; $\frac{5}{8}$" x $\frac{3}{8}$"
Sizes Dried: $\frac{3}{8}$ x 0
Sizes Made: Egg, Nut, Scrn., Stoker

Trade Name: Stonefort
Mng. Equip.: 1 stripping shovel, 3 loading shovels; 1 stripping drill.
Haulage Equip.: 4 Trucks, 5 tractors
Power: 33,000 V. DV. 4000 D.C., 400 A.C.
Prop. Leased & Owned: Life Exp. 17 yrs.; Employees 186; 1 shift; Cap. 3000 T.
1962 Tonnage, 668,154

Allendale Mine
Sls. Agt., Pittsburg & Midway Coal Mining Co.
Loc. .... Wyoming, Stark Co., Ill.
Ship .... Sherwood, CB & Q, C & NW RR's.
Supt. .... Dean Moss
Mine Mgr. .... E. L. Kine
Strip: No. 6 Seam: 42" Th.
Prep. Equip.: Baum Wash.; Driers: Lig. Dms.
Daily Cap. (Cleaned Coal) .... 2800 T.
Sizes Washed: All
Sizes Dried: $\frac{3}{8}$" x 0
Sizes Shpd.: 4" x 1¼"; 2" x 1¼"; 1¼" x $\frac{3}{4}$"; $\frac{3}{4}$" x $\frac{5}{8}$"; $\frac{5}{8}$" x 0"
Major Use Values: Dom. & Steam
Mng. Equip.: Strp. Shvl.; 2 Ldg. Shvls.; 4 Dzrs.; 1 Drag
Haulage Equip.: 6 Trlrs.
Pwr. Pur., 4000 D.C., 440 A.C.
Prop. Owned & Leased: Life Expec. 20 yrs.; Emplys. 98; Daily Cap. 2800 T.
1962 Tonnage, 460,388

For additional data, see pages 429, 443, 449

UNITED ELECTRIC COAL COMPANIES, THE
307 N. Michigan Ave.,
Chicago, Ill.
Pres. .... J. M. Morris
Vice Pres. (Oper.) .... E. J. Hepburn
Vice Pres. (Sales) .... T. J. Tarey
Sec. .... G. H. Utterback
Treas. .... John T. Murray
Comtr. .... Wm. J. Hanhold
Asst. Treas. .... O. A. Alderson
Chief Mining Engr. .... R. H. Inman
Pur. Agt. .... Wm. A. Polty
Prep. Mgr. .... D. K. Burkhalter
Canton, Ill.
Land Engr. .... T. H. Latimer
Dir. of Research & Mech. Devel. J. J. Huey
Chf. Elec. .... J. C. Bettenmayer
1962 Company Production, 4,646,886
Sales Agt., United Electric Coal Cos.

Buckheart Mine No. 17
P. O. .... Canton, Fulton Co., Ill.
Ship .... Canton, CB & Q RR. & Ill. River
Supt. .... L. W. Barto
Supply Clerk .... H. Pilsbury
Elec. .... J. S. Ross
M. Mech. .... D. M. Smith
Pit Foreman .... Davis Campbell
Plant Foreman .... T. H. Shelby
Strip: No. 5 seam: 59" Th.
Designer of Plant: Nelson Davis Co.
Prep. Equip.: 4 Heldon Heavy Media Washers; Oil Dust. Treat.; Crusher; Vib. & Skkr. Scrns.; Pck. Tbl.; Ldg. Bms.; Calcium Freeze Proof
Daily Cap. (Cleaned Coal)(1 shift) 6000 T
Sizes Washed: 6" x 3"; 3" x 4"; 3" x 1¼"; 1¼" x $\frac{5}{8}$"; 1¼" x 5/16"; 1¼" x 28 M; $\frac{5}{8}$" x 28 M
Sizes Shipped: Lmp.; Egg; Nut; Slack; Scr
Tonnage Cleaned, 1960 ... 1,326,250
Mng. Equip.: 1 Strp. Shvl.; 1 Dragline; 2 Ldg. Shvls.; 2 Horiz. Drills; 1 Wheel Excavator
Haulage Equip.: 17 Tractor-Trailers Units
Power Pur.: D.V. 4000 A.C.; 440 A.C.
Prop. Owned: Employees 168; 3 shifts; 7000 T. daily; Life Expec. 25 yrs.
1962 Tonnage, 1,342,412

Cuba Mine No. 9
P. O. .... Cuba, Fulton Co., Ill.
Ship .... Lewistown, CB & Q RR.
Ship .... Cuba, TP & W RR.
Supt. .... C. H. Clayberg
Supply Clerk .... Arlo Turner
Elec. .... W. L. [illegible]
M. Mech. .... Van Brunell
Pit Foreman .... Ray McAdams
Plant Foreman .... J. L. Henry
Strip: No. 5 seam: 30" Th.
Designer of Plant: McNally-Pittsburg Mfg. Co.
Prep. Equip.: McNally-Norton Washery; Heldon Heavy Media; Deister Tbls.; Crusher, Skkr. & Vib. Scrns.; Pck. Tbl.; Ldg. Bms.; Oil Dust. Treat.; Calcium Freeze Proof
Daily Cap. (Cleaned Coal)(1 shift) 4500 T
Sizes Washed: 6" x 4"; 4" x 3"; 3" x 1¼"; 1¼" x $\frac{5}{8}$"; 1¼" x 5/16"; 1¼" x 28 M; $\frac{5}{8}$" x 28 M
Sizes Dried: $\frac{3}{8}$" x 0
Sizes Made: Lmp.; Nut; Pea; Slack; Scr
Tonnage Cleaned, 1960 1,083,285
Mng. Equip.: 1 Strp. Shvl.; 1 Ovr.-bdn. Drill; 1 Ldg. Shvl.; 1 Wheel Excavator
Haulage Equip.: 14 Tractor-Trailer Units
Power Pur.: D.V., 4000 A.C., 440 A.C.
Prop. Owned: Employees 105; 3 shifts; 4500 T. daily; Life Expec. 10 yrs.
1962 Tonnage, 827,180

Fidelity Mine No. 11
P. O. .. DuQuoin, Perry Co., Ill.
Ship .... Pinckneyville, IC & MP RR.
Supt. .... Eric E. Laurell
Chf. Clerk .... J. Underhill
M. Mech. .... Wiley Hobbs
Pit Foreman .... Jack Portner
Plant Foreman .... R. Kelner
Designer of Plant: Koppers Co.
Strip: No. 6 seam: 74" Th.
Prep. Equip.: Koppers-Rheolaveur & McNally-Norton Washery; Dust. Treat.; Crusher; Vib. & Skkr. Scrns.; Pck. Tbl.; Ldg. Bms.; Calcium Freeze Proof; Oil Dust. Treat.
Daily Cap. (Cleaned Coal) (1 shift) 6000 T
Sizes Washed: 7" Lmp.; 7" x 4"; 4" x 3"; 3" x 1¼"; 1¼" x $\frac{5}{8}$"; 1¼" x $\frac{5}{8}$"; $\frac{5}{8}$" x $\frac{3}{8}$"; $\frac{3}{8}$" x 10 M; 1¼" x 28 M; $\frac{5}{8}$" x 28 M; 5/16" Carb.
Sizes Made: Lmp.; Pea; Nut; Egg; Slack; Stkr.
Tonnage Cleaned, 1960 1,408,827
Mng. Equip.: 1 Strp. Shvl.; 1 Wheel Excavator; 2 Overbdn. Drills
Haulage Equip.: 16 Tractor-Trailer Units
Power Pur.; 6600 KVA; D.V. 4000 A.C.; 440 A.C.
Prop. Owned: Employees 148; 3 shifts; 7000 T. daily; Life Expec. 25 yrs.
1962 Tonnage, 1,815,366

Mary Moore Mine No. 27
P. O. Danville, Vermilion Co., Ill.
Ship .... Danville; C&EI RR.
Supt. .... R. Kruser
Plant Foreman .... J. R. Stull
Supply Clerk .... E. Brewer
Strip: Nos. 6 & 7 Seams: 78" Th.
Designer of Plant: United Electric Coal Cos.
Prep. Equip.: Vib. Scrns.; Heavy Media Washer; Oil Type Dust Treat.; $CaCl_2$ Type Freeze-proof Treats.
Daily Cap. (Cleaned Coal) (1 shift) 2840 T
Sizes Washed: 1¼" x 0; 1¼" x 6"
Sizes Shpd.: Scrngs.; Slkr.
Tonnage Cleaned, 1960 213,880
Mng. Equip.: 1 Drag.; 1 Ldg. Shvl.
Haulage Equip.: 8 Trucks
Power Pur.: Mine 4160 A.C.; Plant, 440 A.C.
Prop. Owned: Employees 28; 3 shifts; 1700 T. daily; Life Expec. 10 yrs.
1962 Tonnage, 338,170

Banner Mine
Loc. .... Peoria Co., Ill.
Supt. .... [illegible]
M. Mech. .... F. D. Clarke
Pit Fore. .... A. H. [illegible]
Elec. .... G. W. [illegible]
Plant Fore. .... C. E. Hong
Strip: No. 2 seam
Mng. Equip.: 65 yd. Strip Shvl.
Prep. Equip.: H.M. Wash.; [illegible] Super Air Flow, Filter; Dust. Treat.
Daily Cap. 2500 T.; Employees 47
1962 Tonnage, 723,100

For additional data, see page 427

UTILITY COAL CO.
2828 N. Meridian St.,
Indianapolis 8, Ind.
(Aff. with Big Ten Coal Co., Ill., Dist. 10 & Morgan Coal Co., Ill., Dist. 10)
Pres. .... Harrison Eiteljorg
V. Pres. .... Charles Thomas
Gen. Mgr. .... Miller E. Rogers
Sls. Agt., Reliable Coal & Mining Co.

Marion Mine
P. O. Marion, Williamson Co., Ill.
Ship. Marion; M. P. & C.B.&Q. RR's
Supt. .... Glen Peach
Prep. Mgr. .... Jas. Gordon
Strip; No. 6 seam: 78" Th.
Prep. Equip.: Daniels Heavy Media; McNally Dryclones; Viking Oil Spray Dust. Treat.; 4 Vib. Scrns.; 2 Belt Ldg. Bms.; Bird Humboldt Dryer
Daily Cap. (Cleaned Coal) 1600 T.
Sizes Washed: 8" x $\frac{3}{8}$"
Sizes Dried: $\frac{3}{8}$" x 0; $\frac{3}{8}$" x $\frac{1}{4}$"
Sizes Shpd.: 8" x 3"; 3" x 1¼"; 1¼" x $\frac{5}{8}$"; $\frac{5}{8}$" x $\frac{3}{8}$"; $\frac{3}{8}$" x 10M; 1¼" x 28M.
Major Use Values: Dom. & Indus.
Mng. Equip.: 2 Dozers; 2 Ldg. Shvls.; 1 Drag.; 1 Crldn. Drill
Haulage Equip.: 5 Tract.-Trails.
Power Pur.: Tipple 440 A.C.
Prop. Owned & Leased: Life Expec. 10 yrs.
1962 Tonnage, 222,423

For additional data, see page 426

ZEIGLER COAL & COKE CO.
Box 116, Sparta, Ill.
(Aff. with Bell & Zoller Coal Co., Dist. 10)
Pres. .... Alfred M. Rogers
Gen. Supt. .... E. E. Green
Chf. Clk. .... Charles Parmer
Pur. Agt. .... J. C. [illegible]
Sales Agt., Bell & Zoller Co.

Spartan Mine
P. O. .... Sparta, Randolph Co., Ill.
Ship .... Sparta, M-I, MoP
Mine Mgr. .... Cliff Thomas
Elec. .... Lowell Carter
Supply Clerk .... Earl Ervin
Slope: No. 6 seam: 78" M.
Prep. Equip.: Mrs. Baum Jig; L-B Thermal Dryer; Oil Dust. Treat.
Daily Cap. (Cleaned Coal) .... 4500 T.
Sizes Washed: 7" x 28M
Sizes Dried: 1¼ x 28; $\frac{3}{8}$ x 28M; $\frac{5}{8}$" x 28M
Sizes Shpd.: 8" x 6"; 6" x 3"; 6" x 1¼"; 3" x 1¼"; 1¼" x $\frac{3}{4}$"; 1¼" x $\frac{5}{8}$"; $\frac{5}{8}$" x $\frac{3}{8}$"; 1¼" x $\frac{3}{8}$"; $\frac{3}{8}$" x $\frac{5}{8}$"; 1¼" x 10M; $\frac{5}{8}$" x 10M; 6" x 28M; 1¼" x 28M; $\frac{3}{8}$" x 28M; $\frac{5}{8}$" x 28M
Mng. Equip.: 7 Drills; 6 Ldrs.; 6 Cutters
Haulage Equip.: 10 Shuttle Cars; 36" Conveyr. Belts
Power Pur.:
Prop. Owned: Emplys. 135; 3 shifts; Daily cap. 4000 T.
1962 Tonnage, 881,346

For additional data, see page 430

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1962 TOTAL TONNAGE 48,487,362
1962 UNDERGROUND TONNAGE 23,902,311
1962 STRIP TONNAGE 24,585,051

SIZE OF MINES—1962

500,000 tons and over 34
200,000 to 500,000 12
100,000 to 200,000 6
50,000 to 100,000 9
Less than 50,000 48
(U. S. Bur. Mines)

THIS 1964 ILLINOIS DIRECTORY
26 COMPANIES, 57 MINES

ASSOCIATED COAL CO., INC.
P.O. Box 30, Marion, Ill.
Sls. Agt., Lake Michigan Corp.

Glenview Mine

Loc., Marion, Williamson Co., Ill.
Ship ....Marion, MoPac, RR
Strip: No. 6 Seam
Prep. Equip.: Pck. Tbls.: Oil Treat.: Jet Spray Wash.
Sizes Made: 8"; 4"; 3"; 2"; 1½x¾"; 1½"; 1½x¾" Med. ¾"x0 Carb.; ¾"x0 Carb.
Trade Name: Fairview
Prep. Owned: Life Expec. 10 Yrs. Daily Cap. 1200 T.

BELL & ZOLLER COAL CO.
208 So. LaSalle St.
Chicago 4, Ill.
(Operates also in Dist. 9)
(Aff. with Zeigler Coal & Coke Co., Dist. 10)
Pres..........Stuart Colson
Exec. Vice Pres.....W. F. Landes
Vice Pres. & Treas..C. W. Peterson
Sec..........J. O. Hare
Vice Pres. Sales
Warren P. Wursburg
Vice Pres. Sales Prom.
Wilford Wehrle
Vice Pres. Lake Sales..S. M. Rogers
Mgr. Sales.......Wm. H. Sutton
Asst. to Pres..........M. E. Walsh
Asst. to Exec. Vice Pres.
R. C. Rasmussen
Spec. Rep..........J. W. Morris
Operating Office—Johnston City, Ill.
Gen. Supt..........Arthur Towles
Prep. Engr..........Wesley Smith
Safety Dir..........Coy South
Pur. Agt..........J. C. Davis
Chief Engr..........Gilbert Engram
Maint. Engr..........Wm. McNall
Div. Auditor..........John Brannon
Controller ....John R. Cooley
Sls. Agent, Bell & Zoller Coal Co.

Zeigler No. 3 Mine

P. O....Zeigler, Franklin Co., Ill.
Sh. Pt.
Zeigler Mine, IC, CBQ, MoPac RRs.
Supt..........George Stachura
Mine Mgr..........Mike Sokovich
Supply Clerk..........Ivan Thomas
Prep. Mgr..........Ray Carney
Slope: No. 6 Seam: 96" Th.
Prep. Equip.: Heavy Media Wash.: Baum Jig: Air Tbl.: Calcium Freeze: Mcnts.: Scrns.: Ldg. Bms.: Wax & Oil Spray Dust Treat.
Daily Cap. (Cleaned Coal) (2 Shifts) 5400 T.
Sizes Washed: 7" x 0
Sizes Air Cleaned: 1" x 0
Sizes Shipped: 7 x 3; 3 x 2; 2 x 1¼"; 1¼ x 1; 1¼ x 10M; 1" x 10M; ¾" x 10M; ¾" x 0; Super-X
Tonnage Cleaned, 1961 931,207
Trade Name: Zeigler Superwashed
Mng. Equip.: 7 RT Mng. Mach.; 7 Mbl. Ldg. Machs.; 7 Mbl. Drills; 3 Rock Dust.; 7 Units Roof Bolt
Haulage Equip.: 75 Steel M. Cars; 12 Tr. Locos; 43" T.G.; 14 Shuttle Cars; Mother Belt
Power Purchased: D.V. 250 D.C. Tipple 440 A.C.
Prep. Owned: Employees 258. 2 shifts; Daily Cap. 5530 T.
1963 Tonnage, 885,654

Zeigler No. 4 Mine

P. O....Johnston City, Williamson Co., Ill.
Ship.......Zeigler Mine, IC, MP & CB & Q & C & EI RRs.
Supt..........Drexel Pierce
Mine Mgr..........Guy Robinson
Asst. Supt.......Raymond Gothard
Supply Clerk..........John Aaron
Elect.........Charles Crossman
Prep. Mgr......Courtney Bilderback
Slope: No. 6; 96" Th.
Designer of Plant: McNally-Pittsburg Mfg. Co.
Prep. Equip.: McNally-Pitt. Washery: Deister Tbls.: Thermal Driers: Shkr.: Vib. Scrns.: Crusher: Ldg. Bms.: Mcnts.: Oil Dust Treat.: Calcium Freeze Proof
Daily Cap. (Cleaned Coal) (2 Shifts)..........6000 T.
Sizes Washed: 7 x 0
Sizes Dried: 1 x 0
Sizes Shipped: 7" x 3"; 3" x 2"; 2" x 1¼"; 1¼" x 1"; 1¼" x ¾"; 1" x ¾"; 1¼" x 10M; ¾" x 10M; ¾" x 0
Tonnage Cleaned, 1961 ...1,107,828
Trade Name: Zeigler Superwashed
Mng. Equip.: 6 MBL. Ldrs.; 5 Cont. Miners: Rock Dust.; 2 Units Roof Bolt, Arctic cascade convr.
Haulage Equip.: Convyrs.; 16 Shuttle Cars
Power Purchased: 3500 KVA D.V. 250 D.C., Tipple 440 A.C.
Prep. Owned: 220 Employees; 2 shifts
1963 Tonnage, 1,0[illegible]6,431

Murdock Mine

P. O....Murdock, Douglas Co., Ill.
Ship..........Murdock, B & O RR.
Supt..........[illegible] Williams
Prep. Mgr..........K. W. Neikch
Supply Clerk..........Ray Janes
Chief Elect..........Harry Becker
Shaft: Murdock Seam, 54" Th.
Prep. Equip.: Crusher: Shkr. Scrns.: Jig Washery: Oil Spray Dust Treat.: Calcium Freeze Proof: Pck. Tbls.: Ldg. Bms.
Daily Cap. (Cleaned Coal) (2 Shifts)..........2500 T.
Sizes Washed: 6 x 0
Sizes Shipped: Over 6", over 3", 6 x 1¼, 3 x 1¼, 1¼ x 0; 1 x ¾; 1¼ x ¾
Tonnage Cleaned, 1961 371,182
Trade Name: Murdock Superwashed
Mng. Equip.: 2 Cut. Machs.; 4 Ldrs.; 3 Drills
Haulage Equip.: 42" T.G.; 3 Shuttle Cars; Convyrs.
Power Pur., 250 D.C., 440 A.C.
Prep. Owned: Employees 93; 2 shifts; Daily Cap. 2300 T.
1963 Tonnage, 527,417
For additional data, see page 432

BELLE VALLEY COAL CO.
R.D. 1, Belleville, Ill.
Pres. & Gen. Mgr....C. O. Stiehl
Chief Engr..........H. W. Flood
Sales Agts.:
Schuler & Associates

Belle Valley Mine

Ship.
Belleville, St. Clair Co., L&N, RR.
Supt..........Kenneth Wall
Elecn..........Roland Fish
Chief Clerk..........C. H. Doetsch
Top Foreman....Edward Williamson
Slope: No. 6 Seam; 84" Th.
Prep. Mgr.......Harry Kiedemuller
Designer of Plant: Wemco
Prep. Equip.: WEMCO Heavy Media Washery: Crusher: Screens
Daily Cap. (Cleaned Coal)....600 T.
Sizes: 4 x 0; 3 x ¾; 1¼ x ¾; ¾ x 3/16
Equip.: Ldg. Mach; 4 Tr. Locos T.G. 42"; 16-5 ton steel cars
Power Pur.: D.V. 250 D.C.
Employees 40; 2 shifts; Life Expec. 10 yrs.; Daily Cap. 600 T.
1963 Tonnage, 71,186

BLUE BIRD COAL CO.
226 So. Michigan Ave.,
Chicago, Ill.
Chm. Bd..........T. H. Cochran
Pres..........Richard D. Cochran
Sales Agt...Ender Coal & Coke Co.

Blue Bird No. 5 Mine

P. O.....Harrisburg, Saline Co., Ill.
Ship..........Harrisburg: NYC RR.
Pur. Agt..........H. Hess
Slope: No. 5 Seam; 54" Th.
Prep. Equip.: Deister Tbls.: Cyclones Vib. & Shkr. Scrns.: Pck. Tbls.: Ldg. Bms.
Sizes Washed: 1¼ x 10M; 1" x 10M; ¾ x 10M
Sizes Dried: ¾" x 0"

CARMAC COAL CO.
(See—Thunderbird Collieries Corp.)

**CONSOLIDATION COAL CO.,
TRUAX-TRAER COAL CO. DIV.**
111 No. Wabash Ave.,
Chicago 2, Ill.
(See also N. D.)
Pres..........H. C. Livingston
Vice Pres. (Oper.).......H. M. Tibbs
Vice Pres., Treas. & Sec.,
Henry B. Platt, Jr.
Vice Pres. (Sales).....Jack H. Price
Admin. Asst. to Vice Pres. (Oor.)
Glenn B. Fowler
Gen. Sls. Mgr.......B. E. Herbster
Controller..........S. H. Zagaris
Chf. Engr..........M. H. Shumate
1961 Company Production, 5,601,308
Sales Agts., Truax-Traer Coal Co. Div., Consolidation Coal Co.

Burning Star No. 1 Mine

P. O.......DuQuoin, Perry Co., Ill.
Ship...Pinckneyville, IC & MP RR.
Gen. Mgr..........R. E. Henderson
Asst. Gen. Mgr.....C. D. Heatherly
Supt. (Slope Mine).....J. A. Martin
Supt. (Strip Mine) Ralph T. Tolliver
Engr..........William J. Winters
Supply Clerk.....T. W. Carruthers
Elecn..........C. A. Tyner
Prep. Mgr..........J. L. Dress
M. Mech..........H. L. Singer
Slope: No. 6 seam; 84" Th.
Strip: No. 5 seam; 42" Th.
Prep. Equip.: McNally Wash.: Rot. Brkr.: Raw Coal Storage: Oil Dust. Treat.: Visac Heat Driers: CMI Driers
Mng. Equip.: (Strip) 1 Power Shovel: 1 Dragline; 8 Tractors; 1 Overburden Drill; 2 Ldrs. (Drift): 4 Mng. mach.; 4 loading mach.; 9 Coal Drills; 1 Cont. Miner; 5 Roof Drills
Haulage Equip.: (Strip) 6 Tractor-Truck Units; (Drift): 8 Shuttle cars: Belts; 42" convyrs.
Power pur.: 34,500/4160/440 A.C.
Prep. owned: Life expectancy 10 yrs.; 1 shift; 3300 T. daily
1963 Tonnage, 933,801

Burning Star No. 2 Mine

P. O. ....DuQuoin, Perry Co., Ill.
Ship Pinckneyville, IC & MP RRs.
Gen. Mgr..........R. E. Henderson
Asst. Gen. Mgr.....C. D. Heatherly
Supt..........H. M. Clark
Engr..........William J. Winters
Prep Plt. Foreman John E. Robinson
Supply Clerk..........Neil Rice
Elec..........Yutaka Hattori
M. Mech..........H. L. Singer
Prep. Mgr..........J. L. Dress
Strip: No. 6 seam; 60" to 68" Th.
Prep. Equip.: McNally Wash.: Rot. Brkr.: Raw Coal Storage: Oil Dust. Treat.: Visac Heat Driers: CMI Driers
Mng. Equip.: 1 Strp. & 1 Ldg. Shvls.; 2 Ovbdn. Drills
Haulage Equip.: 18 Tractor-Trailer; 6 Tractors; 12 Pumps
Power Pur.: Dist. Volt. A.C. 34,500/7200/400
Prep. Owned: Life Expec. 20 yrs.; Full Daily Cap. 6200 T.; 1 shift
1963 Tonnage, 1,351,627

Red Ember Mine

P. O..........Fiatt, Fulton Co., Ill.
Ship..........Fiatt, CB&Q RR.
Gen. Mgr..........Gene Long
Gen. Supt..........J. Q. Berta
Engr..........L. Fisher
Mech. Supt..........Roy Lessner
M. Mech..........Elmer McCann
Prep. Engr..........J. L. Dress
Supply Clerk..........Lyle Boughan
Stripping: No. 5 seam; 54" Th.
Designer of Plant: McNally-Pittsburg Mfg. Co.
Prep. Equip.: Norton washery; oil dustless treatment; Crusher; Vib. & Shkr. Screens: Ldg. Bms.: Mcnts.: Visac Driers: CMI Driers
Daily Cap. (Cleaned Coal)...7500 T
Sizes Washed: 6" x 0
Sizes Dried: 1" x 0
Sizes Made: 6" x 4"; 4" x 2"; 2" x 1"; 1" x 0
Mng. Equip.: 2 Strp. & 3 Ldg. Shvls.; 1 Drag.; 2 Wh. Excav.
Haulage Equip.: 17 Trucks, 8 Tracts.
Power Pur.: Dist. Volt 34,500/4160 440 A.C.
Prep. owned & leased: Life Expectancy 20 yrs.; 1 shift; 7500 T. daily
1963 Tonnage, 1,610,658
For additional data, see pages 441, 413, 37, 66, 149, 159, 225, 229, 391, 452, 454, 488, 512, 513, 562, 563, 572, 573

DELTA COAL CORPORATION
(See—Thunderbird Collieries Corp.)

EGYPTIAN MINING CO.
25 S. Main St., Harrisburg, Ill.
Pres..........Robert E. Brandt

4941
1131

DEFENDANT'S
EXHIBIT
241

State of Illinois
Richard B. Ogilvie, *Governor*

1968 Annual Coal, Oil and Gas Report
DEPARTMENT OF MINES AND MINERALS

15

Mines Suspending Operations During 1968 Showing Month of Last Operation

Mine Index No.	Operator	County	Month of last operation
[illegible]	Big Bear Coal Company	Peoria	Apr. [illegible]
[illegible]	Florida Coal Company	[illegible]	[illegible] [illegible]
[illegible]	Main Line Coal Corp. #2	Jackson	May [illegible]

Mines Abandoned During 1968 Showing Month of Last Operation

Mine Index No.	Operator	County	Month of last operation
L-71	Ajax Coal Company, Inc., #1	Jackson	Mar. [illegible]
[illegible]	Blue Bird Coal Co. (Turner Mine #1)	Williamson	Aug. [illegible]
[illegible]	Durbin Coal & Gravel Company	Knox	Aug. [illegible]
L-1	H-B Coal Co., Inc.	Logan	Oct. [illegible]
[illegible]	Easley Coal Co. #2	Jackson	Aug. [illegible]
[illegible]	Lee Coal Co. #2	Vermilion	Jan. [illegible]
[illegible]	Lee Coal Co. (Auger #1)	Vermilion	Dec. 31, [illegible]
[illegible]	Liberty Coal Co. #[illegible]	Williamson	Mar. [illegible]
[illegible]	Old Ben Coal Corp. #[illegible]	Franklin	Feb. [illegible]
[illegible]	Peabody Coal Co. (Utility Highwall Mine)	Williamson	Aug. [illegible]
[illegible]	West Star Coal Co., Inc., #1	Saline	June [illegible]

New Mines Opened — 1968

Mine Index No.	Operator	County	Month Mine Opened
[illegible]	[illegible] Coal Company #[illegible]	Saline	Feb. [illegible]
[illegible]	Lee Coal Company #1 (Auger Mine)	Vermilion	Mar. [illegible]

1133 ~~1913~~

DEFENDANT'S EXHIBIT 242

ALPHA PORTLAND CEMENT COMPANY
15 SOUTH THIRD STREET
EASTON, PA.

R. E. HARTMANN
VICE PRESIDENT
AND SECRETARY

January 22, 1969

Department of Justice
Room 2634 - United States Courthouse
Chicago, Illinois 60604

RE: U.S. vs. General Dynamics Corporation et al., Civil Action No. 67 C 1632 (N.D. Ill.)

Gentlemen:

This will reply to your letter of January 10, 1969 requesting additional information relative to the above-captioned case.

During the period 1964 through 1967 this company used, at the St. Louis, Missouri and LaSalle, Illinois plants, for the purpose for which coal is required, the below listed quantities of gas at the costs as reflected:

	ST. LOUIS		LA SALLE	
	Cu. Ft.	Amount	Cu. Ft.	Amount
1964	1,464,302,000	$334,215	-	$ -
1965	1,861,883,000	400,266	-	-
1966	1,620,065,000	348,314	290,760,200	91,360
1967	1,634,518,000	364,471	384,321,100	109,356

It has been our usual practice to consume gas at the St. Louis plant during the approximate period April 1 to October 31 of each year as an economically advantageous rate structure is available to the company during that period.

DEPARTMENT OF JUSTICE
JAN 24 1969
DIVISION OF RECORDS

SHEET NO. 2 ALPHA PORTLAND CEMENT CO.

TO Department of Justice January 22, 1969

The use of gas at the LaSalle plant was commenced in 1966 to permit the economic evaluation of such fuel as an alternative to coal as well as to permit the repair and rebuilding of coal preparation equipment at that plant.

Very truly yours,

REH/fm

1135

DEFENDANT'S EXHIBIT 243

WISCONSIN ELECTRIC POWER COMPANY

231 WEST MICHIGAN STREET

MILWAUKEE, WISCONSIN 53201

JR

May 21, 1968

Mr. John T. Cusack
Attorney, Midwest Office
Antitrust Division
Department of Justice
Room 2634, United States Courthouse
Chicago, Illinois 60604

60-0-37-920
DEPARTMENT OF JUSTICE
MAY 22 1968
DIVISION OF RECORDS

Re: United States v. General Dynamics Corporation et al., Civil Action No. 67 C 1632 (N.D. Ill.)
60-0-37-920

Dear Mr. Cusack:

This is in reply to your letter of April 9 addressed to Mr. C. F. John requesting information in regard to the above referenced civil action.

The information requested in paragraphs 1 and 2 of your letter is detailed in Tables I and II attached. All coal purchased for the following generating stations for the years 1964 through 1967 was delivered to storage docks by lake vessels during the navigation season for Lake Michigan, which normally extends from April 1 to December 1 each year:

Oak Creek Power Plant
Port Washington Power Plant
Commerce Street Power Plant
East Wells Street Power Plant

This coal was consumed approximately from mid-April of the year in which it was delivered to mid-April of the following year. Coal purchased for use at our Lakeside Power Plant for the same years was consumed during the calendar year in which it was purchased. The footnote of Tables I and II explain the variance in the period coal was purchased and consumed.

In response to your paragraph 3, during the referenced period facilities for generating electricity by utilizing oil and gas were available at the Commerce Street Power Plant. Details in regard to gas and oil consumption are given in Table III attached. Boiler #25 of this plant is the only unit so equipped and was equipped to burn gas or oil exclusively since November, 1964. This unit has a capability of 22,000 kw

Mr. John T. Cusack - Page 2. 5/21/1968.

when supplying 230,000 lbs. per hour of steam for our heating utility. The footnotes to Table III explain the seasonal usage of gas and oil and the portion of each used for steam production at this plant.

In response to paragraph 4, no facilities were available for generating electricity by nuclear energy through the years 1964 through 1967.

Facilities for generating electricity from other sources as requested in paragraph 5 are limited to hydroelectric and diesel plants of Wisconsin Michigan Power Company, a wholly owned subsidiary of Wisconsin Electric Power Company. The information which you requested regarding these facilities is given in Table IV attached.

Data in response to paragraph 6 of your letter are not available.

You will note from the several documents attached that the majority of our coal is derived from mines in Illinois and western Kentucky. We believe that the acquisition by General Dynamics Corporation of the United Electric Coal Companies made it possible for the latter companies to have available financial resources for the development of mining properties and to increase the availability of coal sources from these regions.

You may wish to correct your records to indicate that Mr. C. F. John retired as Vice President in Charge of Power on December 31, 1965.

Very truly yours,

Robert H. Gorske

Robert H. Gorske General Counsel

Attach.

Paul Weir, founder, consultant

1917 Cable address "WEIRCO"

DEFENDANT'S EXHIBIT 252

PAUL WEIR COMPANY
INCORPORATED
MINING ENGINEERS AND GEOLOGISTS
(312) 346-0275
20 NORTH WACKER DRIVE
CHICAGO, ILLINOIS 60606

Clayton G. Ball, chairman of the board
John P. Weir, president
John E. Good, senior vice president
John S. Snyder, controller

Vice presidents
Raymond E. Zimmerman
Erwin Gammeter
Donald H. Dowlin
David J. Kachik
George W. Boulter
Gerald C. Clark

June 8, 1970

Mr. Reuben L. Hedlund
Kirkland, Ellis, Hodson,
Chaffetz & Masters
2900 Prudential Plaza
Chicago, Illinois 60601

Dear Mr. Hedlund:

In regard to the United States v. General Dynamics litigation, it is my understanding that the Department of Justice has introduced into evidence an excerpt of the 1951 study made by the Paul Weir Company under subcontract to the United States Army Corps of Engineers. Apparently, the excerpt in question, entitled "Coal Data Sheets Showing Recoverable Coal Reserves In Illinois Available For Commercial Use And Synthetic Liquid Fuels Manufacture", has been designated Government Exhibit No. 308 and has been introduced to place in issue the estimated "Recoverable Strip Coal Reserves" in Illinois contained therein. It is the position of the Paul Weir Company that the conclusions relating to Illinois strip reserves reached in that report were valid ones, when viewed in light of the parameters of that report and the limitations inherent in the underlying data at that time. It is the purpose of this letter to delineate these matters so that the summary report offered into evidence may be viewed in its proper context.

First, the survey made for the Corps of Engineers was national in scope and included information on four raw materials, only one of which was coal. The Paul Weir Company received the coal subcontract from the prime contractor, Ford, Bacon & Davis. We collected information on coal deposits in 24 states. The Illinois report, from which GX No. 308 is taken, is contained in two main volumes and one supplement.

PAUL WEIR COMPANY

Mr. Reuben L. Hedlund
June 8, 1970
Page 2

The excerpt which constitutes the trial exhibit is only one part of the supplementary volume, which also contains detailed statistical charts and tables on a township by township basis. Thus, it can be readily seen that the brief excerpt submitted into evidence is but a small portion of the published material concerning Illinois coal made by Paul Weir Company for this study.

Secondly, our performance under the terms of the subcontract was confined to a study of information obtainable from then-existing published material, and there was no authorization for any field studies or primary research. Thus, the sources for our report and its conclusions were eclectic in nature. It is our belief that this report was the first such comprehensive digest of existing data on coal reserves in the State of Illinois. This report was completed two years before the principal reserve study of the Illinois Geological Survey was undertaken; and, of course, the definitive survey of Illinois strip reserves made by the IGS was not commenced until 1957, seven years after the publication date of the report in question. In 1950, the only published materials which pertained exclusively to Illinois strip reserves and which were available for our use were two Illinois Geological Survey reports, published in 1926 and 1929 respectively, which reported the occurrence of strip coal in two very localized areas of the state and a series of reconnaissance maps prepared by the Department of Agriculture in 1946 and 1947.

Thirdly, in addition to technological innovations and developments in the strip mining industry, the development of more precise and accurate information-gathering techniques in the last twenty years also accounts for the discrepancy between our 1951 recoverable strip reserve estimate and an equivalent figure of today. For example, at that time, all geological maps were charted on about a one" to one mile scale and at a 15 minute quadrangle variant. In contrast, maps drawn on a one":2000' scale and on a 7-1/2 minute quadrangle variant are available today. Such breakthroughs in data collection increased the body of knowledge of coal

reserves substantially and necessarily make more precise estimates based thereon. Such an increment in accumulated data specifically enhance the reliability of strip coal reserve estimates. As was stated at page 57 of Volume I of the 1951 report, "In estimating strippable reserves, the amount and character of the available information are relatively much more important than in estimating underground reserves, because of the determinative interdependence of factors, such as the thickness and continuity of coal bed and the thickness and character of overburden in a relatively small proportion of the general coal-bearing area."

Finally, the terms of our subcontract set definitional limits as to what reserves were to be considered "strippable." Although this provision established the maximum depth for "strip reserves," the contract anticipated the problems inherent in reaching conclusions based upon derivative sources of information and provided that reserves lesser in depth could be defined as "underground coal" in the judgment of the subcontractor. Accordingly, commensurate with the degree of reliability of the given underlying data and the purpose of the assignment, Paul Weir Company classified some reserves as "deep" rather than "strip," when information on intermediate categories of deposits was insufficient.

When the above-mentioned facts are taken into consideration, we feel that the 1951 estimate is consistent with the purposes of the assignment undertaken by the Paul Weir Company and that comparisons between its conclusions and contemporary knowledge are meaningless.

Sincerely,

Clayton G. Ball

Clayton G. Ball
Chairman of the Board
Paul Weir Company

CGB/

ABATEMENT OF SULFUR OXIDE EMISSIONS FROM STATIONARY COMBUSTION SOURCES

Prepared by
Ad Hoc Panel on Control of Sulfur Dioxide from Stationary Combustion Sources
Committee on Air Quality Management
Committees on Pollution Abatement and Control
Division of Engineering
National Research Council

Washington, D.C.
1970

This is the report of a study undertaken by the Committee on Air Quality Management *Ad Hoc* Panel on Control of Sulfur Oxide from Stationary Combustion Sources for the National Academy of Engineering in execution of work under Contract No. CPA 22-69-31 with the National Air Pollution Control Administration, Consumer Protection and Environmental Health Service, Public Health Service, U.S. Department of Health, Education, and Welfare.

PREFACE

Because the air, water, and land on earth are limited, we, as a nation, must plan and work together to ensure the preservation of an acceptable environment. In this report of a study on the control of sulfur oxide emissions into the atmosphere, primarily from electricity generating stations, an effort has been made to place the findings of the study in perspective with the entire problem of environmental quality management.

On the basis of problem definition, a study of need, a study of engineering constraints, and an analysis of technological requirements and alternatives, this report outlines a government-industry program for research, development, and demonstration of potential control processes.

No attempt has been made, however, to deal with such problems of sulfur oxide emissions as their effect on health and other biological aspects. Important though such studies may be, they are outside the scope of the *Ad Hoc* Panel on Control of Sulfur Oxide from Stationary Combustion Sources.

The members of the panel, along with the members of the Committee on Air Quality Management, share the objectives of the Congress as representing the determination of the people to restore and maintain the quality of our air resources and the objectives of the National Air Pollution Control Administration of the Department of Health, Education, and Welfare as the Federal "lead agency" to assure significant progress by an early date. The panel hopes that the results of its study will be useful in the attainment of these objectives.

The panel's estimation of the present status of sulfur control technology is based primarily on presentations by 23 research and industrial organizations that came to Washington to discuss the results of their process studies and their proposals for further

work. In addition, 23 other organizations provided information by correspondence.

The panel appreciates the cooperation received from industrial and research organizations with active programs in sulfur oxide control. The panel is particularly grateful to Mr. Paul W. Spaite, Director, Bureau of Engineering and Physical Sciences, National Air Pollution Control Administration, and his staff for their outstanding support.

A summary of the study and a brief statement of conclusions are presented first in the report for the benefit of those who may wish to gain an overview of the panel's efforts. These are followed by an introduction covering the background of the study, the roles of the National Academy of Sciences and the National Academy of Engineering, and the nature of the sulfur oxide emissions problem. The remaining sections of the report cover the impact of the nation's growing requirements for electricity upon the sulfur oxide emissions problem and review the possibilities for abatement of sulfur oxide emissions through the widespread use of nuclear power plants, the use of sulfur-free or low-sulfur fuels, and the development and application of technology to control sulfur oxide emissions. A strategy for the research, development, and demonstration of this technology is presented.

Appendixes to the report contain lists of organizations that made presentations and correspondents who supplied information for the study, lists of research and development activities in sulfur oxide pollution control in the United States and abroad, and a selective bibliography.

It is hoped this report will provide a basis for increased governmental and public understanding of the problems of sulfur oxide abatement and control, and will direct attention and adequate assignment of resources to the orderly and expeditious solution of this portion of the nation's problems of environmental quality management.

Thomas H. Chilton, *Chairman*

NATIONAL ACADEMY OF SCIENCES-
NATIONAL ACADEMY OF ENGINEERING
NATIONAL RESEARCH COUNCIL
Division of Engineering

COMMITTEE ON AIR QUALITY MANAGEMENT
AD HOC PANEL ON CONTROL OF SULFUR OXIDE
FROM STATIONARY COMBUSTION SOURCES

Thomas H. Chilton, Retired, E.I. du Pont de Nemours & Co., Inc., *Chairman*
Richard E. Chaddock, Hercules Incorporated
Vance R. Cooper, General Electric Company
George T. Cowherd, Jr., Consolidated Edison Co. of New York, Inc.
H. L. Falkenberry, Tennessee Valley Authority
C. Howard Hardesty, Continental Oil Company
Robert L. Hershey, Retired, E.I. du Pont de Nemours & Co., Inc.
R. M. Lundberg, Commonwealth Edison Company
Robert L. Pigford, University of California, Berkeley
Elliott J. Roberts, Dorr-Oliver, Incorporated
Thomas K. Sherwood, Retired, Massachusetts Institute of Technology, *Ex Officio*
Jack A. Simon, Illinois State Geological Survey

Staff
R. W. Crozier, *Executive Secretary*, Committees on Pollution Abatement and Control, National Research Council
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Donnell H. Nicchitta, Administrative Secretary, Committees on Pollution Abatement and Control, National Research Council

Liaison Representative-NAPCA
Paul W. Spaite, Director, Bureau of Engineering and Physical Sciences, National Air Pollution Control Administration, U.S. Department of Health, Education and Welfare

CONTENTS

TABLES

FIGURES

I

SUMMARY AND CONCLUSIONS

Controlling and improving the quality of our environmental resources is a growing concern of the nation. National and regional goals and standards for air quality management are being defined. Capital investments of billions of dollars will be required to install processes to meet these standards. Keeping these costs within bounds, while still attaining an acceptable level of control within the shortest practical period of time, will call for the best efforts and most careful planning at all levels from individuals, civic groups, and companies through local, regional, state, and Federal agencies.

The emission of SO_2* from combustion of sulfur-bearing coal and oil, primarily for the generation of electrical energy, is second only to the emission of pollutants from internal combustion engines in quantity of pollutants discharged to the national air environment.

During the next 20 years, the national requirement for electrical energy is expected to more than triple. The supply of natural gas, a low-sulfur fuel, is expected to decrease in about 10 years, and petroleum products may reach their maximum availability in about 30 years. To supply the needed electricity, the use of coal is expected to triple by the year 2000, when it is expected that the use of nuclear energy will about equal the use of coal, after which the requirement for coal will start a downward trend.

The substitution of low-sulfur fuels, the only presently available method for reducing SO_2 emissions, is restricted by the limited availability

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*The symbol SO_2 is used in this report to designate the sulfur oxides in stack gases (SO_2 plus 1 percent to 2 percent of SO_3).

of natural gas, low-sulfur oil, and low-sulfur coal. More rapid expansion of the application of nuclear energy is constrained by engineering and economic problems, in addition to siting problems, that are of growing concern to all planning of major electricity generating installations. By the late 1980's, new fossil-fueled plants may employ magnetohydrodynamic (MHD) generators, followed by conventional steam boilers or by advanced Brayton or Rankine power cycles. The combined energy conversion efficiency of such plants is expected to be in the range of 50 percent to 60 percent compared with about 40 percent for conventional plants, which would result in a corresponding decrease in SO_2 emissions. However, the high operating temperature of MHD units may result in increased NO_x emissions.

In addition to improving the energy conversion efficiency, the fast breeder nuclear reactor produces a net gain of fissionable material and thereby reduces the net cost of fuel. The Atomic Energy Commission is planning a 500 MW fast breeder demonstration plant for 1976 and expects the first commercial units to start up about 1985 in the United States.

Therefore, *the reduction of SO_2 emissions from stationary combustion sources, in the next 5 to 20 years, will depend very largely on the development, demonstration, and application of a combination of technologies designed to prevent the sulfur in coal and petroleum products from reaching the atmosphere through the combustion processes.*

The technology for removal of sulfur from oil is being developed by a number of oil companies, and the panel does not believe that NAPCA should contribute significantly to these developments.

Although broader application and refinement of existing technology could increase the quantity of low-sulfur coal available, there are no cleaning or washing processes presently in sight that have the potential for substantially reducing sulfur content below levels presently being achieved. This emphasizes

the need for new concepts in engineering and chemical approaches to the desulfurization of coal.

In addition to joint support by groups of utilities, a number of industrial organizations have committed significant funds to research, development, and demonstration of sulfur emission control processes and equipment. An increase in these activities, together with increased support by the Federal Government, is needed.

The panel reviewed the status of United States and foreign sulfur oxide abatement and control processes and firmly concluded that, *contrary to widely held belief, commercially proven technology for control of sulfur oxides from combustion processes does not exist.*

Efforts to force the broad-scale installation of unproven processes would be unwise; the operating risks are too great to justify such action, and there is a real danger that such efforts would, in the end, delay effective SO_2 emission control. *A high level of government support is needed for several years to encourage research, engineering development, and demonstration of a variety of the more promising processes, as may be suited to specific local and regional conditions, to bring these processes to full-scale operating efficiency at the earliest practical date. This can be done most expeditiously if Federal support, in addition to industry commitments, is provided at the appropriate time and in the needed amounts.*

Federal support for the development of the following control approaches is suggested:

1. **"Throw-away" processes for removal of SO_2 from stack gases, such as limestone injection, which produce a presently nonmarketable product**

2. **New combustion concepts, such as fluidized bed combustion (FBC), which fixes the sulfur as a sulfate during combus-**

tion and prevents its release as SO_2 to the stack

3. Chemical recovery processes, which produce salable SO_2, sulfuric acid, elemental sulfur, or fertilizers

4. Coal gasification processes, which produce sulfur-free fuels

5. New concepts in engineering and chemical approaches to the desulfurization of coal

The limestone injection processes, with adequate particulate control, should be commercially demonstrated within the next 1 to 3 years and, if successful, can be installed in many existing plants.

Several sulfur-recovery processes appear to be ready for scale-up to commercial demonstration size (100,000 kW or larger boilers). Full-scale demonstration of the industrial reliability of these processes is 4 to 10 years away. Some of them can be installed in a portion of existing plants or engineered into future plants.

New combustion technology may be available for industrial application in 5 to 10 years. Efficient coal gasification processes, which are 5 to 10 years away, have the potential for producing pipeline-quality, low-sulfur gas for supplementing existing supplies of natural gas or for producing a product of less than pipeline-quality, but adequate for power generation. Such fuels seem likely to become increasingly competitive for use in power production as the cost for controlling all pollutants (SO_2, NO_x, and fine particulates) increases the costs for conventional systems.

These time estimates are realistic only if there is dedication and a positive commitment on the part of government agencies, utilities, fuel suppliers, and equipment manufacturers to support the orderly

development and timely application of the more promising processes.

In recommending a 5-year plan for future work, the panel places special emphasis on the following:

1. Complete development of the limestone process should be given high priority because it is applicable to many existing boilers and is closer than others to demonstrated industrial application.

2. For new power plants and some existing plants, it is expected that sulfur-recovery processes will be necessary to keep costs for future control within reasonable limits.

3. NAPCA should continue to support the development and demonstration of new concepts in combustion technology, sulfur-recovery, and coal-desulfurization processes.

4. Research should be supported on ways to combine the abatement of nitrogen oxide and particulates with sulfur oxide control.

5. Elemental sulfur is a more desirable by-product than sulfuric acid or sulfur dioxide. The conversion of sulfur dioxide to sulfur is not a well established process, and it is important that the technology and costs of this conversion be thoroughly studied.

6. NAPCA should employ a *process engineering and construction firm* to project costs on a *common basis* for all the promising processes at various stages in their development to aid in making scale-up decisions.

II

INTRODUCTION

A. BACKGROUND OF THE STUDY

The concern of Americans for the deterioration of the nation's air resources is reflected in Public Law 90-148 as amended, the Air Quality Act of 1967, enacted by the 90th Congress on November 21, 1967. Responsibility for carrying out the provisions of the law is assigned to the Secretary of the Department of Health, Education, and Welfare.

The purposes of the Act are set forth in Section 101(b) as:

1. to protect and enhance the quality of the nation's air resources so as to promote the public health and welfare and the productive capacity of its population;

2. to initiate and accelerate a national research and development program to achieve the prevention and control of air pollution;

3. to provide technical and financial assistance to State and local governments in connection with the development and execution of their air pollution prevention and control programs; and

4. to encourage and assist the development and operation of regional air pollution control programs.

Special emphasis (Section 104) is given to research and development into new and improved methods for the prevention and control of air pollution resulting from the combustion of fuels. In addition to providing for laboratory and pilot plant testing, Section 104(a)(4) calls upon the Secretary of the Department of Health, Education, and Welfare to "con-

struct, operate, and maintain, or assist in meeting the cost of the construction, operation and maintenance of new or improved demonstration plants or processes which have promise of accomplishing the purposes of this Act."

The Clean Air Act recognizes the regional nature of air pollution problems. One of the functions of the Federal Government under the 1967 legislation is the designation of air quality control regions in all those areas in which air pollution constitutes a serious threat to health and welfare. Once air quality regions are designated, and NAPCA has issued criteria documents describing the harmful effects of specific pollutants, together with documents describing techniques for controlling the pollutants, it becomes the responsibility of the states in the regions to develop air quality standards and plans for enforcing them. In 1969, NAPCA issued criteria on two of the major pollutants--particulate matter and the sulfur oxides--together with the required supporting documents on techniques available for preventing and controlling their emission into the atmosphere. In March 1970, NAPCA issued air quality criteria and recommended control techniques for carbon monoxide, photochemical oxidants, and hydrocarbons.[16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26*]

The Clean Air Act, as amended, states in Section 101(a)(3) "that the prevention and control of air pollution at its source is the primary responsibility of State and local governments," in Section 101 (a)(4) "that Federal financial assistance and leadership is essential for the development of cooperative Federal, State, regional, and local programs to prevent and control air pollution," and, in Section 101 (b)(4), that a major purpose of the Act is "to encourage and assist the development and operation of regional air pollution control programs."

Federal assistance is provided in two major ways--financial and technical. Financial assistance

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*Refer to numbered items in the bibliography contained in Appendix E of this report.

to air pollution control agencies is authorized under Section 105 of the Act. Under Section 106, financial assistance for planning for air quality standards and implementation plans in interstate air quality control regions is authorized.

The National Air Pollution Control Administration also provides technical assistance in conducting emission inventories, air quality monitoring and data analysis, and diffusion modeling. Diffusion modeling involves combining meteorological and emission data to predict air quality. These services are particularly helpful in attempting to test various emission reduction strategies.

The Air Quality Act of 1967 has created a new role for the Federal Government in air pollution control. The Act states that air quality standards that the states develop for an air quality control region become effective when the Secretary of the Department of Health, Education, and Welfare determines that such standards are "consistent with the air quality criteria," and it states that an implementation plan becomes effective when the Secretary determines "that the plan is consistent with the purposes of the Act insofar as it assures achieving such standards of air quality within a reasonable time."

What may be considered a "reasonable time" for attainment of an air quality standard will depend on a number of factors, including the availability of applicable control techniques and, particularly, the nature and seriousness of the adverse effects of the pollutants involved. Every implementation plan must include a timetable for reaching compliance with the projected requirements for the prevention, abatement, and control of air pollution. This timetable must provide for meaningful increments of progress over relatively short intervals, such as 1-year or 2-year periods, during the total timespan covered by the implementation plan.

B. THE ROLES OF THE NATIONAL ACADEMY OF SCIENCES AND THE NATIONAL ACADEMY OF ENGINEERING

The National Academy of Sciences and the National Academy of Engineering established the Environmental Studies Board in 1967 to coordinate activities of the two Academies in the environmental field. One of the first acts of this board was to create four committees within the Division of Engineering of the National Research Council on air, water, noise, and solid waste mancgement, respectively. These committees have an engineering orientation and are available for advice and assistance to the Congress and to agencies of the executive branch having responsibility for pollution abatement and control. Needed interaction and coordination of the committees are provided through liaison activities of the Environmental Studies Board.

On June 20, 1969, the Department of Health, Education, and Welfare, through the National Air Pollution Control Administration, requested the National Academy of Engineering to make a comprehensive review of present industry and government research and development programs directed toward control of sulfur oxides effluents from stationary sources of combustion. The requested study would include technical and economic potentials, adequacy of scope, proper integration with other similar efforts, and the responsiveness to national needs.

The request was accepted after review and coordination by the Environmental Studies Board with other environmental activities of the National Academy of Engineering and the National Academy of Sciences. The task was assigned to the National Research Council's Committee on Air Quality Management, which in turn requested its *Ad Hoc* Panel on Control of Sulfur Oxide from Stationary Combustion Sources to carry out the study.

Because meeting national energy requirements is only one of man's activities that may result in unacceptable acceleration of environmental degradation, studies of abatement technology for other sources of SO_2 and other air pollutants will be made soon.

C. NATURE OF THE SULFUR OXIDE PROBLEM

At an early meeting of the panel with Dr. John T. Middleton, Commissioner of NAPCA, and subsequent meetings with Mr. Paul W. Spaite, Director of the Bureau of Engineering and Physical Sciences of NAPCA, and other members of the NAPCA staff, the panel was presented data on projected sulfur oxides emission with various levels of control. The panel members considered these data to be realistic, based on authoritative sources, and interpreted rationally and conservatively; and the members were impressed with the magnitude and urgency of the problem of sulfur oxides emission to the atmosphere. *The data and projections gave rise to the conclusion that positive action will be required to prevent the emission of sulfur oxides into the ambient air from more than quadrupling by the year 2000.*

The requirement for electrical power is projected to increase at an annual rate of 6 percent during the next 30 years. It is generally agreed that the generation and distribution of this quantity of electrical energy, using presently available fuels and technology, will result in unacceptable levels of environmental degradation. As previously noted, the use of sulfur-bearing fuels to generate electrical energy is only one of man's activities contributing to the decline in quality of our air resources, but it is a major source of SO_2.

NAPCA chose SO_2 emitted to the atmosphere from electricity generating plants for first attention because: (1) this is the largest man-made source of sulfur oxides; (2) it is widely dispersed nationally, but is largely concentrated in or near urban centers; (3) it is growing at about 6 percent per year; (4) it is intimately related to the national and international flow of energy resources; (5) it is important to regional economic development; and (6) it is critical to continued national well-being, security, and economic growth. Moreover, *while national and regional goals and standards are being defined, the processing methods presently available to attain these goals are inadequate for the task.*

Worldwide emission of sulfur into the atmosphere arises from biological, geological, and industrial activity.[11] Of the man-made sources, coal and oil combustion for electricity generation accounts for about 50 percent, other combustion of coal 16 percent, other combustion of oil 9 percent, primary and secondary smelting 12 percent, petroleum refining 7 percent; and miscellaneous sources including coke and sulfuric acid production, burning coal refuse banks, and refuse incineration 6 percent.

III

ENERGY REQUIREMENTS AND AIR POLLUTION CONTROL

A review of sulfur oxide abatement and control technology gives rise to concern as to the future supply of electricity and the future availability and use of fuels. There are important matters of policy and management regarding future energy conversion and consumption that bear directly and importantly on environmental problems, such as: emission of sulfur oxides, nitrogen oxides, particulates, carbon dioxide, carbon monoxide, and other pollutants from fossil fuels combustion; thermal pollution; siting of generating facilities and distribution systems; fuels policy and availability; radioactive pollution and disposal of radioactive wastes; and technological, political, jurisdictional, and economic limitations and constraints.

Electricity generation, sulfur oxide emission control, and other environmental factors are closely interrelated and require an integrated systems approach. The objective of providing for the nation's growing power needs is subject to the constraints of maintaining environmental quality, fuels availability, and technical developments. Within this framework lie the trade-offs of shifting generation, improved transmission, and the development of control processes. Overriding all of these is the long-term consequence of each alternative.

A. ELECTRICITY GENERATION

The Federal Power Commission now states that the 1970 requirement, including reasonable reserves, for electrical generating capacity is nearly 340 million kW. This requirement is expected to be nearly double by 1980 and to exceed 1 billion kW in 1990.

Figure 1 shows the electricity generation and fuels utilization forecast (assuming early development of the breeder reactor). At present, about 65 percent of the energy for electricity generation comes from coal, with natural gas and oil supplying most of the

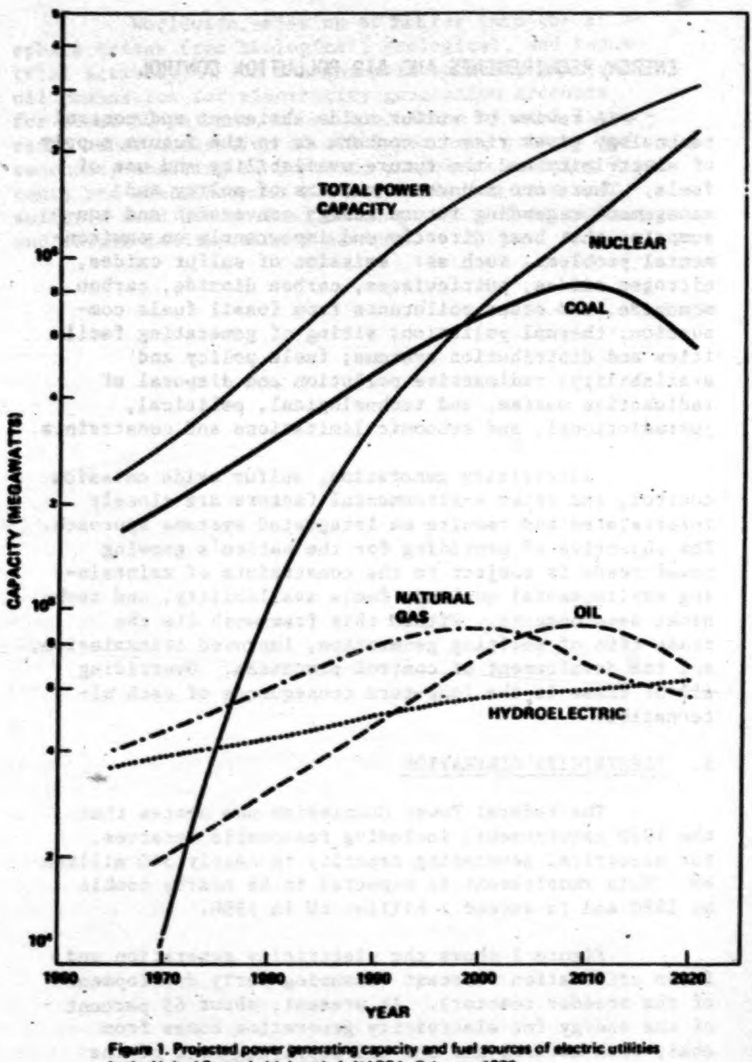

Figure 1. Projected power generating capacity and fuel sources of electric utilities in the United States (with breeder). NAPCA, February 1970.

remainder. It is predicted that the use of nuclear energy will increase rapidly and will exceed coal as an energy source around the year 2000. Because of the need to burn more coal to supply the needed power, sulfur emissions would be expected to increase more than fourfold by the year 2000, unless effective control processes are developed and applied.

Most of the new generating capacity installed between now and 1990 will be provided by some 250 large power plants of greater than 1,000 MW capacity.[2] The siting problem will generally be one of assuring that the relatively small number of large plants are adequately planned and located to meet the goals of providing low-cost, reliable power and minimizing the adverse effects on our environment. With an onsite investment of about $200 million to $400 million each, these new plants will be among the larger industrial establishments in the nation. Including support and auxiliary activities, they will represent approximately $80 billion of capital investment, which will be profoundly affected by the public interest.

B. SULFUR OXIDE EMISSIONS

The demand for electric power is increasing so rapidly that sulfur oxides emissions may increase even allowing for: (1) projected construction of nuclear power plants; (2) substitution of gas or low-sulfur fuel oil at locations where they are available; (3) use of coal of reduced sulfur content to the extent that can be expected; (4) introduction of improved combustion methods; and (5) application of improved stack-gas treatment and sulfur recovery processes.

Even with a national commitment to orderly but urgent plans for application of new technology, the best that can be hoped for through the year 2000 is a total sulfur oxides emission rate from all utilities somewhere near the present level. Near-term improvement in the quality of ambient air at ground level in urban areas may be brought about by resorting to dispersion of facilities, by use of tall stacks, or by load or fuel shifting under adverse meteorological

conditions. Sulfur oxides emission data and projections for the United States are shown in Table 1 and Figure 2.

Nuclear power plants emit no SO_2; essentially the same can be said for plants using natural gas. The technology for removal of sulfur from fuel oil appears to be reasonably well in hand. Further development of hydroelectric power will not be a major factor. The import of liquefied petroleum gases will most likely be increased to the limit of economic availability. Despite these factors, the use of coal will steadily increase and is projected to more than triple by the year 2000, before leveling off as large nuclear power stations replace those burning fossil fuels (Fieure 1). About 75 percent of the sulfur oxides discharged into the atmosphere from man-made sources comes from the combustion of coal and oil. Gasoline contains almost no sulfur, so emissions from automobiles contribute little SO_2. But the combustion of coal, now averaging about 2.7 percent sulfur and forecast to increase to 3.5 percent by 2000, accounts for 65 percent of the total SO_2. The combustion of heavy fuel oil contributes about 12 percent.

TABLE 1

ESTIMATED POTENTIAL SULFUR DIOXIDE POLLUTION WITHOUT ABATEMENT[(a)]

UNITED STATES

	Annual Emission of Sulfur Dioxide (Millions of tons)				
	1967	1970	1980	1990	2000
Power plant operation (coal and oil)[(b)]	15.0	20.0	41.1	62.0	94.5
Other combustion of coal	5.1	4.8	4.0	3.1	1.6
Combustion of petroleum products (excluding power plant oil)	2.8	3.4	3.9	4.3	5.1
Smelting of metallic ores	3.8	4.0	5.3	7.1	9.6
Petroleum refinery operation	2.1	2.4	4.0	6.5	10.5
Miscellaneous sources[(c)]	2.0	2.0	2.6	3.4	4.5
Total	30.8	36.6	60.9	86.4	125.8

(a) February 1970 estimates by National Air Pollution Control Administration, excluding transportation.
(b) See Figure 2. With breeder reactor.
(c) Includes coke processing, sulfuric acid plants, coal refuse banks, refuse incineration, and pulp and paper manufacturing.

Stack gases from fossil-fueled power plants contain about 1,000 to 3,000 ppm of SO_2, depending on the amount of sulfur in the fuel (1 ppm = 2860 $\mu g/m^3$ at standard conditions). Detrimental effects on vegeta-

tion, materials, and human health are first noticed in areas having 0.03 to 0.04 ppm (annual mean) SO_2 concentration.[5,14,15,20] Thus, a 100,000-fold dilution or reduction in concentration is required, on the average, by the time the SO_2 reaches ground level. SO_2 concentrations are near and, in some cases, at times above these levels in several urban areas of the United States.[20]

A number of SO_2 monitoring studies have been made near power plants, and there are various theoretical and computer models for predicting dispersion from stacks and resulting ground-level concentrations for different meteorological and topographic situations. These are intended to show the relation between stack emissions and the permissible concentrations.[20] Such studies have served as the basis for decisions to require use of fuels having lower sulfur content or the use of SO_2 emission control equipment.

The high dilution from stack level to ground level of SO_2 concentration will be required even with development of control devices. The most efficient removal processes can be expected to reduce stack gas concentrations of SO_2 by about 99 percent, which will result in an effluent that could still be above acceptable ground level concentrations. In addition to SO_2 dilution, tall stacks will be needed to disperse carbon dioxide, nitrogen oxide, and water vapor and to provide mixing with air to raise the oxygen content.

In some cases, the 1 percent sulfur limit in fuels has been found to be inadequate, and several regions are considering further reducing the permissible sulfur content. The New York-New Jersey Metropolitan region has set standards limiting sulfur to a maximum of 1.5 percent in fuels that are burned in existing power plants. Other regions are considering similar limits. Bituminous coal containing more than 1.0 percent sulfur cannot now be sold in New Jersey, and the limit will drop to 0.2 percent in October 1971. But the supply of less than 1.0 percent sulfur coal is limited; it appears that it would be impossible to provide the needed fuels if this standard were enforced across the country.

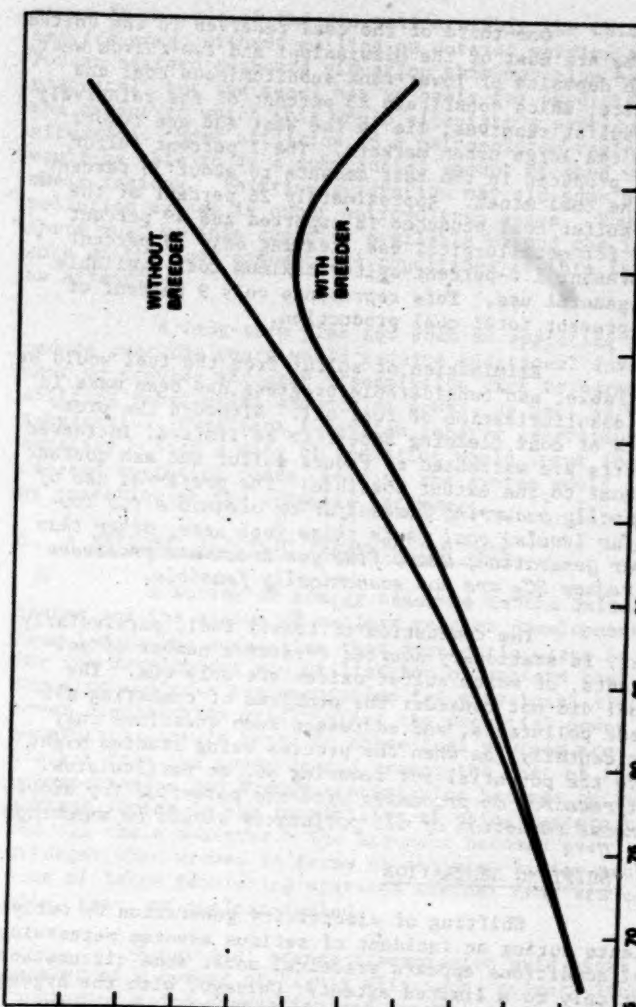

Figure 2. Comparison between projections for total power plant uncontrolled SO_2 emissions. NAPCA, February 1970.

One-third of the coal reserves in the United States are east of the Mississippi and two-thirds west. Large deposits of lower-rank subbituminous coal and lignite, which constitute 83 percent of the relatively low-sulfur reserves, lie in the West and are remote from the large urban markets. The 1 percent sulfur coal produced in the East amounts to about 36 percent of the coal mined. Approximately 26 percent of the low-sulfur coal produced is exported and 49 percent sold for metallurgical use, leaving only 25 percent of present 1.0-percent-sulfur-maximum coal available for general use. This represents only 9 percent of the present total coal production.

Elimination of sulfur from the fuel would be desirable, and considerable progress has been made in the desulfurization of fuel oil. Although the prospects of coal cleaning appear to be limited, increased efforts are warranted to reduce sulfur and ash content in coal to the extent possible. *The preferred use of naturally occurring low-sulfur or cleanable (to low-sulfur levels) coal is in those fuel uses, other than power generation, where flue gas treatment processes to reduce* SO_2 *are not economically feasible.*

The combustion of fossil fuel, particularly coal, in stationary sources creates a number of pollutants, of which sulfur oxides are only one. The panel did not consider the problems of combating all these pollutants, and addressed such questions only incidentally, as when the process being studied might have the potential for removing NO_x or particulates. But, *research on processes with the potential for simultaneous reduction of all pollutants should be encouraged.*

C. SHIFTING GENERATION

Shifting of electricity generation to outlying plants during an incident of serious adverse meteorological conditions appears practical under some circumstances, but only to a limited extent. Chicago, with the Argonne National Laboratory assisting, is developing a future power distribution model for the city. This is a NAPCA-supported activity. It appears possible to shift

about 25 percent of the generation within the Chicago service area, without calling on outside service areas. For an eastern seaboard situation this may also be practical, but the panel has no basis for predicting the extent to which this would alleviate a particular situation. Most utilities in a metropolitan region would be able to do a substantial amount of good within their regions. Shifting generation may aid some peak pollution crises in other metropolitan areas. However, there must be idle capacity available beyond the influence of the poor atmospheric conditions if this is to be effective.

A long-term plan for such an operating procedure over the years would require additional investment to provide stronger transmission ties to permit shifting substantial amounts of power, as well as very substantial investment in system reserve generating capacity. Such a mode of operation would incur increased operating costs, because the system would not be operating at its economic optimum.

D. A NATIONAL ELECTRIC TRANSMISSION GRID

A survey of energy reserves in the United States and the status of nuclear reactor development have led to the suggestion that systematic plans be made for the development and utilization of western coal deposits and to a recommendation for a national electric power transmission grid.[12] Since the potential power generation centers based on these fuel sources are distant from the power demand areas, the cost of fuel transportation and energy transmission becomes an important factor in the feasibility of using western coal and oil shale reserves. The argument becomes even stronger when viewed in terms of the many siting problems of large generating stations whether they are coal-, oil-, gas-, or nuclear-fueled.

A national energy transmission grid might consist of a number of highly efficient, primary lines connecting major generating and consuming areas of the country. Secondary tie lines would then branch out from the primary lines much like the existing power-pool

transmission lines. Preliminary economic analysis[12] indicates feasibility and additional potential benefits in communication and by-products manufacture. Planning, coordination, and implementation of such a venture must be accomplished at the national level. It is appropriate to note here that transmission lines pose significant environmental problems of their own, which may be solved eventually by placing them underground.

The design, construction, and utilization of a very low resistance (super-conductive) national electric energy transmission system would have many advantages, including: (1) implementation of an effective national fuels and energy policy; (2) management of environmental factors related to energy generation, transmission, and utilization; and, (3) improvement of security and reliability of energy sources, generation, transmission, and utilization.

Long-term, broad-scale planning of this magnitude is important in meeting the problems of environmental quality, energy requirements, economic development, and national security.

E. LONG-TERM ENVIRONMENTAL CONSIDERATIONS

The buildup of CO_2 in the atmosphere has not been an important consideration in most air quality improvement planning, and the *ad hoc* panel was not charged with reporting on the long-term global temperature and ecological effects of increasing concentrations of long-lived air pollutants. But is appropriate to remark that CO_2 and submicron-size particulates are the only contaminants resulting from combustion and reduction processes that may be of importance to global ecology. A portion of the submicron particles are sulfate aerosols formed by the reaction of SO_2 in the atmosphere.

Combustion of fossil fuels, a major source of SO_2, is also the source of perhaps 50 percent of the atmospheric buildup of CO_2. Because of this relationship to energy requirements and fuels availability, the panel believes that a discussion of SO_2 pollution must also include recognition of the possible long-term

effects of increasing levels of CO_2.[10] By the year 2000, it is estimated that there will be a 25 percent increase in CO_2 in the atmosphere, compared to the amount present during the nineteenth century. It is further estimated that this increase may affect the earth's radiation balance causing a corresponding increase in the average temperature near the earth's surface.

However, it has been pointed out[6] that there is also a possible worldwide change in the amount of atmospheric fine particles. In addition to particles rising from the earth's surface, significant quantities may be deposited directly in the stratosphere by supersonic transports when they come into extensive use. An increase in fine particulate materials, some of which are SO_2 decay products, may have the effect of increasing the reflectivity of the earth's atmosphere and reducing the amount of radiation received from the sun.[11] This effect would be the opposite of that caused by an increase in CO_2. It is suggested that the large-scale cooling trend observed in the Northern Hemisphere since about 1955 is due to the disturbance of the radiation balance by fine particles and that this effect has already reversed any warming trend due to CO_2.

Whichever may be the case, *it is clear that considerable uncertainty exists as to the effect of long-lived pollutants on the environment.*

Nuclear power presents several potential air pollution problems.[5] Solid waste from radioactive materials in spent fuel rods appears to be a relatively small air pollution problem but is a significant solid waste disposal problem. There are important questions regarding the effects of small amounts of tritium (half-life of 12.26 years) present in the cooling water. The tritium may enter biological systems and produce radiation effects and damage during its decay. Finally, krypton-85 (half-life of 10.4 years) released at the reactor and the fuel reprocessing plant might accumulate in the atmosphere over an extended period, much like carbon dioxide. At some time it may become necessary to collect the tritium and krypton for storage rather than release to the environment.

IV

ENERGY RESEARCH

The National Air Pollution Control Administration has been designated the Federal "lead agency" to provide objectivity, coordination, emphasis, and support to the national efforts to restore and control the quality of our air environment, including:

1. Accumulation, interpretation, and dissemination of all pertinent information

2. Coordination of short-, medium-, and long-range planning of research, development, and demonstration activities of Federal groups such as the Atomic Energy Commission, Tennessee Valley Authority, Federal Power Commission, Bureau of Mines, Office of Coal Research; and state, regional, and local agencies as they relate to air quality factors resulting from extraction, processing, transportation, and utilization of energy resources

3. Planning, initiation, coordination, and funding of research, development, and demonstration of broadly acceptable systems, subsystems, and components as required to reduce air pollution to acceptable levels

Accomplishment of these objectives will require a high level of planning and coordination between the several governmental, research, legislative, industrial, and civic groups involved to: (1) evaluate feasible and acceptable alternative courses of action, (2) determine present and future consequences of specific action or inaction, (3) evaluate the impact of changes on one or another element of the system, (4) determine priorities and funding levels, and (5) select the most broadly acceptable courses of action.

The complexities of the national energy-generation and energy-utilization system will increase with

time. However, careful planning and coordination of national and regional efforts, not only for SO_2 control, but also for control of other air, water, thermal, visual, and solid waste pollutants, will minimize future problems related to environmental degradation associated with plant siting, transmission systems, fuels utilization, engineering feasibility, economics, and public acceptability. Planning and coordination activities of this magnitude present a major national challenge to keep pace with the 6 percent projected annual increase in electricity requirements and still maintain an acceptable environment.

Each year the Federal Government supports research and development to improve methods for producing, converting, and transmitting the primary energy sources--petroleum, gas, coal, oil shale, uranium, and water power. Table 2[1] provides an accounting, by primary energy source, of Federal research and development funds currently being devoted to the task of assuring an abundant supply of energy at reasonable costs to meet the nation's future needs, with minimum impairment of the quality of the environment.

In addition, industry spends hundreds of millions of dollars annually for research and development, with the petroleum industry accounting for a substantial portion of the private expenditures in the energy field. Substantial amounts are spent by utilities and manufacturers on electric power generation and transmission equipment and nuclear fission as part of their facilities development. However, industrial research and development expenditures on coal, oil shale, hydroelectric power, and controlled fusion are but a fraction of the Federal program in this area.

The important bases for viewing research and development expenditures in Table 2 are the energy generation patterns in 1980 and 1990 (Figure 1), and these, in turn, are influenced by the success of present research and development. The relative stage of development of each form of energy conversion must also be considered, since the costs of developing a new technology, such as nuclear fission or fusion, are

TABLE 2

FEDERAL RESEARCH AND DEVELOPMENT EXPENDITURES BY PRIMARY ENERGY SOURCE
(Excludes projects less than $500,000)

		In Millions by Fiscal Year		
		1968	1969	1970 Est.
Uranium and Thorium				
AEC	Fast Breeder Reactors	82	102	122
	Other Breeders and Converters	82	62	50
	General Reactor Technology and Safety	91	97	104
	Total	255	261	276
Coal				
Interior Bureau of Mines		9	9	11
	Office of Coal Research	12	14	13
	Total	21	23	24
Petroleum and Natural Gas				
Interior Bureau of Mines		3	3	3
Oil Shale				
Interior Bureau of Mines		1	2	2
Thermonuclear Fusion				
AEC		27	29	34
	Total	31	34	39
General R&D				
AEC	Plowshare Underground Engineering	3	1	1
HEW	Air Pollution	8	12	15
Interior	Explosives Research	1	1	1
NSF	Energetics Engineering	3	3	3
TVA		1	1	1
	Total	16	18	21
	Over-all Total	323	336	360

greater than those for improving existing systems involving other forms of energy.

The energy conversion efficiency of fossil-fueled power plants appears to have stabilized after gradually increasing over the years. New fossil-fueled steam power plants currently have efficiencies of about 40 percent in converting the fuel combustion energy into electrical energy. Present commercial nuclear power plants range from about 30 to 35 percent in conversion efficiency, and breeder reactors are expected to reach about 40 percent efficiency. Combined cycle systems, are, in principle, more efficient energy conversion facilities. For magnetohydrodynamic generation using fossil fuels, with a steam plant to utilize the energy contained in the hot gases leaving the magnetohydrodynamic unit, the combined efficiency is projected to be on the order of 50 to 60 percent.[12] The high temperature required will cause increased nitrogen oxides formation. Improved efficiency reduces the amount of fuel required and the amount of heat rejected to the environment to meet a given demand. For sulfur-bearing fuels, the SO_2 emission would be correspondingly reduced.

V

FACTORS OF FUELS UTILIZATION

Fuel use patterns are dependent upon supply (availability) and on certain technical developments in fuel production, energy conversion, and energy transmission. Projections indicate maximum production of natural gas in the United States within 10 years and of petroleum products within 30 years.[8]

The Atomic Energy Commission estimates that in the year 2000 nuclear energy will supply about 44 percent of the national electricity generating capacity, coal about 41 percent, and gas, oil, and hydroelectric power about 15 percent. Present fuel sources for electricity generation are: nuclear, 1 percent; coal, 65 percent; and gas, oil, and hydroelectric, 34 percent. Serious delays in construction schedules of several nuclear power plants have occurred during the past year, and the cost estimates per installed kW have risen from about \$130 in 1967 to about \$200 in 1970.[13] Cost for fossil-fueled plants were about \$110 to \$130 per kW in 1967, and are \$120 to \$160 per kW in 1970. These costs include particulate-control devices, but do not include equipment for SO_2 or NO_x control. ***Recently, a number of orders for fossil-fueled plants, with shorter lead time and lower capital costs, have been placed by utilities to meet power requirements that nuclear plants might have met under earlier construction schedules.***

These factors indicate a greatly expanded use of coal as an energy source during the next 30 to 40 years (Figure 1). The United States has an assured reserve of coal and oil shale to meet its energy needs for hundreds of years to come. Some changes in the schedule are dependent upon the development of:

1. **Early resolutions to siting, environment, and economic problems related to present and future power plant development**

2. Processes for more effective coal desulfurization

3. Processes for conversion of coal to "clean" gaseous or liquid fuels

4. The fast breeder nuclear reactor, which will reduce nuclear fission fuels costs and extend nuclear fuel resources

5. Various combined cycles such as magnetohydrodynamic generators, which are potentially more efficient than steam turbine generators

6. Industrially efficient processes for the extraction of oil and gas products from oil shale

7. The controlled nuclear fusion reactor, which would make large amounts of energy available

Difficulties with equipment delivery and plant siting have already seriously delayed the construction of generating capacity in parts of the United States. The Federal Power Commission states that 39 of 181 major systems have reserves of less than 10 percent peak load. There is a real possibility of power shortages and "brown-outs" in some power pool areas during peak-load periods of the next several years.

At many inland sites, river water and ground water are no longer available in sufficient quantity to be used for once-through cooling; hence, evaporative cooling towers have come into fairly common use. At several locations, in the eastern as well as far western parts of the country, even the demand for make-up water for cooling towers (about 2 to 3 percent of the once-through rate) exceeds the amounts available from rivers and existing wells without endangering the river flow or the water table. In England, this situation has resulted in installation of closed-cycle cooling systems that exchange heat to the air through finned

heat exchangers.[2] Costs, of course, increase substantially with the transition from once-through to closed-cycle cooling systems.

There is also some thought that man's future needs may be better served if substantial reserves of coal, petroleum, natural gas, and oil shale are set aside for the rapidly growing requirement for chemical industry feed stocks. Such a reserve will, of course, depend largely on the beneficial application of developing nuclear technology. Thus, the critical need for development and application of technology to control pollution resulting from fossil fuel (particularly coal) combustion may well occur between now and 1985 or 1990.

In view of these consideration, it is evident that SO_2 problems that are generally restricted to coal use (and in a smaller way to ore smelting and petroleum use) will grow until SO_2 control processes or other energy sources are developed. Thus, *the SO_2 abatement problem fits into the larger problems of fuel policy and management.*

VI

TIME PHASES OF TECHNICAL DEVELOPMENTS

Successful development and application of several control processes and the breeder reactor are crucial in the abatement of sulfur oxide emission to the atmosphere. As shown in Figure 2, assuming the breeder reactor comes into wide application after the year 2000, coal consumption and sulfur emission would peak and decrease rapidly even without emission control.

Research on fast breeder nuclear reactors is proceeding rapidly in several countries. The British 60 MW pilot breeder reactor at Dounreay, Scotland, went critical in 1959 and has operated continuously except for a 1-year shutdown during 1968-69 to repair a leak. The United States 150 MW "Fermi" breeder reactor in Monroe, Michigan, first went critical in 1963. It was shut down in October 1966 due to a subassembly meltdown and is scheduled to start up again in 1970. The Atomic Energy Commission is now selecting a site for a 500 MW demonstration breeder power reactor to start in 1976. Projections call for the first commercial breeder reactors of the 1,000 MW size to start up about 1985 in the United States.

Fuel substitution has already begun to be practiced but is restricted by the limited availability of low-sulfur oil, coal, and natural gas. More intensive cleaning of coal to remove pyrite may make a contribution to sulfur-emission control comparable to fuel substitution as it comes into wider use in the next few years. Although limestone processes for the removal of SO_2 from stack gases—which do not produce a marketable product—should be commercially proven in the next 1 to 3 years, broad application of these processes will require several more years. Several product-producing processes for SO_2 removal should be commercially available in the mid-1970's or early 1980's and should find wide application in the new coal-fired plants. With adequate funding and experimental success, new combustion technology should be available in 5 to 8 years.

As with the breeder reactor, there is no assurance that the control processes will be developed as predicted. *The time estimates are realistic only if there is a positive commitment on an urgent basis by government agencies, utilities, fuel suppliers, and equipment manufacturers to support the orderly development and timely application of these processes.*

The sequence of technical developments must be coordinated with the plans for compliance with air pollution control regulations and the availability and use patterns of various fuels. As the national air quality control regions implement their criteria and emission control schemes to improve the quality of the air, there will be a growing need for the different kinds of technology and a shifting in types of fuel used.

For example, in the Washington, D.C., area, plans are being developed for the National Capital Interstate Air Quality Control Region.[7] In addition to a reduction in suspended particulate matter, it is proposed that all fuels burned in the region must contain 1 percent or less sulfur. It is also proposed that, after July 1, 1971, distillate fuel oils (ASTM No. 1 and No. 2) should contain 0.3 percent or less sulfur. Fuels containing in excess of 1 percent sulfur could be burned, provided control equipment to desulfurize stack gases had been installed or other methods were used that would produce results equivalent to the burning of fuel containing 1 percent or less sulfur.

All fuel-burning installations constructed and all fuel-burning installations altered or modified for use of a different fuel having a maximum heat input of less than 250 million Btu's per hour would be required to burn gaseous fuels, provided that distillate fuel oils could be used for not more than 30 days in any calendar year. However, liquid and solid fuels could be burned, provided it were demonstrated that sulfur oxides, particulate matter, and nitrogen oxides emissions would be equal to or less than would result from burning gaseous fuels to accomplish the same heating objective

At this time, the complete substitution of gas, or low-sulfur oil, for coal in Washington, D.C., appears to be the only possible way, short of establishing an all-electric city, to achieve the long-term goals that are being considered.[7] Other proposed actions include control of open burning and tighter limits on emissions of particulates and sulfur oxides from incinerators and industrial operations. These suggestions, of course, are not to be taken as courses of action recommended by the panel.

To meet such goals in other cities, it would be necessary for industrial plants to install more efficient particulate control on all stacks, and SO_2 scrubbers on many processes. Heating systems would have to convert to gas, low-sulfur oil, or electricity, depending upon fuel availability. Existing power plants would need to convert to oil or gas or add stack removal of SO_2, and new plants would use nuclear energy, gas, or perhaps something like fluidized bed combustion of coal.

Such shifting would require the expansion of gas and oil supply systems. Since natural gas reserves are limited, both coal gasification and importing of liquefied natural gas would probably be necessary to meet the increased demand.

There is a possibility that a number of the newly created air quality control regions will adopt plans such as those described above in the next few years. *Care must be exercised at the local, regional, and national levels to assure that realistic criteria and plans are adopted which can be implemented in concert with the development of technology and the systematic use of our energy resources.*

There is a real danger that the public may be led to expect environmental improvements at a rate that cannot be realized. This is not to say that high goals should not be established, but rather that realistic and coordinated implementation plans must be adopted.

VII

SUPPORT OF TECHNOLOGICAL PROGRESS

The objective of support of technological progress in SO_2 emissions control is to advance the state of the art with all deliberate urgency consistent with prudent engineering and economic judgment and national needs.

The Federal effort to achieve the necessary sulfur oxide control should be in partnership with the electric-power industry, equipment manufacturers, and the fuels industry. Eventually, sulfur oxide control may create a market that will offer some industrial incentives. Meanwhile, implementation of SO_2 control plans is a major national problem that will require large expenditures by the utilities and large costs to consumers, unless technology is developed that will minimize these costs.

In seeking suggestions for enlisting the private sector in support and augmentation of the Federal effort, the panel found that in recent years many companies have spent up to several million dollars developing their processes to the pilot scale and beyond (Chapter VIII). Other companies, some with interesting technological approaches, do not have adequate funds even for bench-scale work. Within industry, the competition for research and development money is such that the expenditure of $5 million to $10 million of a company's funds on commercial demonstration of one process may be a poor research and development risk when compared with alternative projects of corporate interest.

A. COAL INDUSTRY

The coal industry is not process-research oriented and its air-pollution research and development has been fragmented. To date, the industry's effort has been limited to a few modest projects that have been conducted by several major companies and with sponsorship by Bituminous Coal Research, Incorporated

(BCR). Work within individual companies has been largely concentrated on methods for removing ash and sulfur from coal. The work at BCR, which is supported broadly by the industry, has been devoted to stack gas cleaning processes and coal cleaning, with the predominant emphasis on the latter.

B. EQUIPMENT MANUFACTURERS

The panel learned that the equipment suppliers see no immediate profit potential in the research and development of new SO_2 control equipment under present accounting and taxing policies. What the equipment manufacturers do develop can seldom be protected from use by competition, because very little of such equipment is proprietary or subject to patents that cannot be circumvented. A manufacturer may invest his money and develop a sulfur control process using equipment that he manufactures, only to find that similar equipment is available from many manufacturers, and the utility applying the process may seek competitive bids. Consequently, patents on equipment of this type are regarded as relatively worthless. Patents on a process may be valuable, but the overall situation is such that little acceleration of the research effort can be expected to follow automatically in the private sector, even when sulfur control regulations become more stringent.

Despite these considerations, equipment manufacturers are developing new equipment for air pollution control applications and have participated in a number of joint pilot, demonstration, and feasibility studies.

C. UTILITY COMPANIES

As regulated monopolies, electrical utility companies are subject to the control of various governmental bodies, Federal, state, and local. Consequently, funds spent by utilities for development and application of pollution control processes may not be readily included in their capital structure, which is the basis for establishing consumer rates.

The utility companies, however, are supporting sulfur oxide emission control studies individually and jointly. Over 25 utilities are participating in research, development, and demonstration work on several promising processes (Chapter VIII). The panel agreed on the following points with respect to support by the utility companies of research, development, and demonstration (R,D,&D).

1. Funds spent for development and application of pollution control processes may not have the potential of self-liquidation under present rate-making policies.

2. Many utilities located in urban areas are making determined efforts to secure reliable sources of low-sulfur fuels and installing equipment for multiple fuels capability.

3. The costs of developing and applying control processes will be high; the utilities are neither equipped nor staffed to do the kind of process development and demonstration that is needed. Because of the expense and time involved, it is probably not realistic to expect individual companies to carry out impressive internal R,D,&D programs.

4. The technological risk of applying processes that are inadequately demonstrated is too great to force acceptance and installation of these processes. The most likely effect of legislative pressure will be to force the use of the limited supplies of available low-sulfur fuels. Therefore, until reliable processes are adequately demonstrated, the effectiveness of legislative pressures will be limited.

5. It might be possible for utilities to do more cooperative R,D,&D. Regulatory and taxing agencies might consider adjusting their policies to encourage such activity.

D. FEDERAL GOVERNMENT

Even if additional cooperative funding by the coal industry, equipment manufacturers, utility companies, and process developers can be arranged, government support will be needed for many years to encourage development, demonstration, and application of sulfur oxide control technology. *Unless the necessary technology becomes available, the country may have to choose between clean air and electricity.*

The crux of the problem is its urgency with respect to lead time and degree of applicability of any single process. The schedule for abatement of the emission of sulfur oxides reduces the lead time to a very short period. In order to demonstrate a variety of processes which might be applicable to specific conditions, *the reduction of lead time and the diversity of processes required demand an intensive and concerted effort substantially greater than normal industrial process development.*

Although no control process has yet reached the stage of demonstrated full-scale application in a power plant, several methods that may be suited to particular sets of conditions are under development and should be brought to a stage of industrial efficiency with all deliberate speed. *This can be accomplished most expeditiously by adequate funding of NAPCA in its role as Federal "lead agency" to assure significant progress in an acceptable period of time.*

There are three stages of process development at which Federal support and encouragement are justified:

The first stage is in unrestricted broad-ranging investigations. Such pioneering investigations should normally be restricted to bench-scale work and are worth supporting on a continuing basis.

The second stage involves pilot-plant trials of new processes that appear to be promising.

The third stage comes after pilot-plant trials have been concluded, and when the most promising processes are considered ready for demonstration on a scale that would provide engineering and economic data that could be projected with confidence to large operating units. Such large-scale demonstrations are necessary and will be quite expensive, running into several million dollars for each process selected. This is a critical point in the application of new technology. National needs will be most effectively accomplished by a full partnership (financial and technical) between government agencies, utilities, equipment manufacturers, process developers, and fuel suppliers.

In addition to support of research and development, governmental assistance may be provided through changes in tax and patent policies and provisions for Federal funding of "risk capital." The proposed Tax Reform Act allows accelerated amortization of pollution control equipment. The prospect of profitable patents is an incentive for further research by industry. Several government agencies are reviewing patent policy at this time to determine what changes might be made to encourage research, development, and application of processes designed for pollution control. The Patent Office has recently announced its intention to accelerate the handling of applications dealing with pollution control inventions.

In addition, the Subcommittee on Air and Water Pollution of the Senate Committee on Public Works has heard testimony in recent hearings on S.2005--The Resource Recovery Act of 1969, S.3469--The Wastes Reclamation and Recycling Act of 1970, and the Amendment to S.2005, cited as the National Materials Policy Act of 1969. Federal provision for "risk capital" was one of a variety of subjects discussed. Other approaches of financing of research, development, demonstration, and application of processes and facilities designed to control various types of pollution are being considered at the Federal executive and legislative level.

VIII

PRESENT STATUS OF RESEARCH AND TECHNOLOGY

A. AVAILABILITY OF TECHNOLOGY

Although the panel is optimistic that acceptable sulfur oxides control technology will be developed, it concludes that this technology is not yet commercially proven. Moreover, a rapid pace must be maintained in pursuit of the technical objectives, if only to prevent conditions from getting worse. Even when the expected technology becomes available, it will be too late to prevent a significant rise in total sulfur emissions during the next several years.

Five general approaches might be made to sulfur oxides control problems:

1. Undertake a crash program to build nuclear power plants

2. Remove sulfur from fuels before they are burned

3. Remove sulfur from fuels during the combustion process

4. Remove the SO_2 from the combustion gases before emission to the atmosphere

5. Employ very high stacks and remote siting so that the gases are dispersed and diluted to an acceptable level

The first approach is impractical because of the prohibitive expense and inability to meet even present construction commitments. Some combination of the second, third, and fourth approaches offers the best promise in the United States. However, the processes to accomplish sulfur removal from coals before and during combustion, and from combustion gases, are not adequately developed, and are not immediately acceptable for wide application. Tall stacks and

remote siting, the fifth approach, are being promoted in England and to some extent in the United States.

Sulfur is readily removed from distillate oils, and the technology is well established. Residual fuel oils are more difficult to treat, because they contain metals that deposit on the solid catalysts employed. The petroleum industry has invested heavily in the development of ways to desulfurize fuel oil, and there is no doubt that some of these methods will work. The plants required are costly, and the added refining step of reducing the residual fuel oil from 2.6 to less than 1.0 percent sulfur will probably increase the price to the power station by 50 to 80 cents per barrel. This represents an increase in fuel cost of 20 to 35 percent. Fifty cents per barrel of oil is equivalent to an increase of about 0.7 mills per kWh in power costs.

Sulfur in coal is present principally as the mineral pyrite and in complex organic compounds; in these two forms, it exists in widely varying ratios. With some coals, pyrite can be largely removed by grinding and washing, but, on the average, only about half can be removed, using existing coal cleaning technology. It appears that organic sulfur may be removed only by hydrogenation, liquefication and gasification processes.

Preliminary results of NAPCA's survey of naturally occurring low-sulfur coals and washability characterization tests of coals available for uses other than for metallurgical coke production suggest that of the steam-coal production: 8 percent has 1 percent or less sulfur as mined and could be cleaned further; 11 percent is coal with over 1 percent sulfur that is easily cleaned; and 6 percent is coal with over 1 percent sulfur that is cleanable at a higher cost. Thus, perhaps, 25 percent of the steam-coal production is capable of being cleaned to produce coal with a maximum of 1 percent sulfur.

NAPCA further estimates that refinement and broader application of coal cleaning technology might

result in an average reduction in sulfur content of the remaining 75 percent of steam coals by as much as 40 percent.

Coal washing costs may range from 25 to 75 cents per ton of cleaned product.

Where fuel desulfurization is practical, it offers the most obvious and direct method to reduce SO_2 pollution from combustion. Several processes are under development for the production of liquid and gaseous fuels from coal, and liquid fuels from oil shale, and will perhaps be demonstrated to be industrially feasible within a decade. Meanwhile, most of the needed coal cannot be desulfurized to a maximum of 1 percent sulfur by use of presently available technology.

At least two processes offer hope for removal of sulfur during combustion: (1) "fluidized bed" combustion, and (2) "molten iron bath" combustion. Optimistically, the perfection of these techniques as commerical processes is 3 to 8 years away, and there is some question that either can be retrofitted into existing plants. If successful processes can be developed, their major application will be in plants that are engineered and constructed after the processes are determined to be applicable on a commercial scale.

Many ways of removing SO_2 from stack gases are being actively investigated—all involving some means of contacting the gas with a substance that removes SO_2. At least 25 such processes are under development in this country by industry and by NAPCA (Appendix C), and others are under development in Japan and Europe (Appendix D). Most are bench-scale laboratory projects, but several have reached the pilot-plant stage (10- to 25-MW equivalent gas streams). Only the limestone-wet scrubbing process has been installed in sizable operating power plants. Several of these processes will probably be technological successes, but the efficiencies are not yet well established for even the most advanced. Projected costs range up to 1 mill per kWh and, in some cases, higher, depending upon method of financing.

Although SO_2 emissions are not decreased by remote siting and tall stacks, these measures help reduce ground-level SO_2 concentrations in urban areas. As previously discussed, even with application of sulfur removal processes, tall stacks will continue to be necessary for large power stations to disperse and dilute all remaining emissions, including carbon dioxide, nitrogen oxide, and water vapor.

It should also be noted that the possiblity of establishing one national air quality control region and broader international and even global cooperation in environmental quality management may require national emission standards.

The future of sulfur control is not hard to predict in general terms. The country is committed to reducing air pollution, and increasingly stringent standards regarding sulfur concentrations in the ambient air are being established. Users of high-sulfur fuels will attempt to switch to natural gas, desulfurized fuel oils, or low-sulfur coals, all of which are in limited supply. These will command a premium price over present fuels. Where practical, the coal industry will find more intensive treatment of steam coals profitable. Where possible, new mines in known low-sulfur coal deposits will also be opened. It normally takes about 3 years to bring a new mine into full production.

Because these developments will not meet the total requirements of low-sulfur fuels necessary to control the continuing increase in sulfur emissions, many presently operating utilities will have no near-term alternative except to install facilities to remove sulfur from stack gases. Probably, the simpler methods, which produce "throw-away" by-products, will be the first to be adopted by many existing plants. The more complicated processes, which produce sulfuric acid, SO_2, or elemental sulfur, may be demonstrated in 3 to 10 years.

By perhaps 1980 or 1985, sulfur emissions stemming from smelters and the combustion of fossil fuels will be under fairly good control, although total sulfur emissions will have risen substantially over those at the present time. By 1975 to 1985, there may be ways to burn coal, such as by fluidized-bed combustion in the presence of lime, to fix the sulfur so it is not carried by the stack gases.

B. THE NEED FOR COMMERCIAL DEMONSTRATION

It is important to note that industrially proven technology for the control of sulfur oxides resulting from fossil fuel combustion does not now exist. Only one of the several processes under development has been installed in 100-MW or larger boilers, and it has operated only intermittently.

Data on processing variables accumulated during each stage of process development are evaluated to determine the feasibility of scale-up to the next stage. If feasibility at the bench and pilot scale has been established, prototype industrial scale operation for a minimum of 1 year is necessary to secure sufficient knowledge of the process to establish control parameters, operating reliability and efficiency, maintenance requirements, adequacy of materials and engineering, and ability of the process to meet air quality objectives.

Consequently, *there is an urgent need for commercial demonstration of the more promising processes, to make reliable engineering and economic data available to engineers who are designing full-scale facilities to meet specific local and regional conditions.* The panel's definition of proven industrial-scale acceptability is satisfactory operation on a 100-MW or larger unit for more than 1 year. Also, technical and economic data developed must be adequate for confident projection to full commercial scale. Pilot scale refers to investigation using flue gas in the capacity range of 10 to 25 MW. Smaller sizes and studies using synthetic gas mixtures are considered to be bench scale.

Estimates of industrial-scale feasibili , and adequacy of a process based on paper studies or bench-scale projections are, by their very nature, too speculative to be reliable in making large-scale economic or engineering choices between alternative processes. Such estimates do, however, provide a basis for decisions related to the next level of scale-up. The estimates of installed cost per kilowatt range from $4 to $40 for the processes under development. If the figure were $10, the cost to install control equipment in existing coal-fired power plants would be about $2.2 billion. Total operating costs may be of the order of 0.5 mill per kWh. These are not reliable estimates of the ultimate cost to the consumer of electricity, but they do serve to indicate the magnitude of the problem of SO_2 control.

Even though the technical feasibility of a process were indicated on a pilot-plant scale, industry would be understandably hesitant to fund a large installation prior to full-scale evaluation. For a utility, the risks of failure to meet air quality objectives—as well as operational objectives—are great. For the nation, the possibility of delaying effective SO_2 control by installing equipment that does not do an adequate job is also great. When national objectives call for accelerated construction of high risk, large investment, and the use of unproven processes, it is proper for the government to share in the risks by participation in those portions of the project that are first-of-a-kind engineering demonstration units.

The development of several of the processes for removal of sulfur from stack gases is well advanced. Pilot plants of up to 25 MW have demonstrated to varying degrees the technical feasibility of at least three of these developments. The diversity of the schemes being developed is gratifying, because quite different technical solutions will be required to meet the wide variety of situations in which sulfur control is necessary.

The panel believes that it would be appropriate and very much in the national interest for NAPCA,

under Section 104(a)(4) of the Clear Air Act of 1967, to provide support of several million dollars, in partnership with industry, to expedite the first commercial demonstration installation of each of several promising processes for SO_2 control.

C. BACK-FITTING EXISTING PLANTS

The dry- and wet-limestone processes could probably be used by many existing plants. These are by no means the final solution, and other processes involving by-product recovery should be developed.

Many stations have limited areas in which they can dispose of the ash, and would have to haul it away. For some older plants in crowded areas, very little space is available; forcing them to utilize large quantities of limestone could result in their conversion from coal to a low-sulfur oil. Sometimes, simply upgrading the electrostatic precipitator for the dry-limestone process would cost more than to convert from coal to an oil-fired unit utilizing low-sulfur oil. In addition, for a given precipitator efficiency, a threefold increase in fly ash will nearly triple the particulate emission.

The existing smaller power plants have the other alternatives of obtaining low-sulfur coal, oil, or gas, if supplies of these fuels are available. These alternatives are also available to large plants, but the panel believes that, *from a national point of view, the most logical use for the low-sulfur coal is in commercial and industrial plants, small power plants, space heating, and for production of metallurgical coke.*

The forward-looking utilities are providing space in new plants, in anticipation of the necessity of installing corrective measures for flue gas treatment. They are allocating space or buying enough land to enable them to fit in the technology more easily when it is available. One restriction of this policy is that it provides only for the type of process that would take gases at the usual discharge temperature

of 300°F. It would not easily permit installation of a process that requires use of the high-temperature part of the boiler. The plan is to minimize the back-fitting cost on a 300°F process. Those processes that are designed to operate at 600°F to 900°F will require about 3 years' lead time, and the back-fitting will cost much more than if control technology were available and could be incorporated in the initial design.

D. CENTRAL RECOVERY FACILITY

Utilities may find product-producing processes more attractive if a central chemical processing plant can be employed to collect and regenerate the absorbents or adsorbents from several installations. This appears to be an interesting possibility in connection with several of the schemes that produce salable chemicals.

The suggestion has been made that the chemical industry be brought into partnership with the electric power industry. It is feasible to have a separate chemical operation that would serve a number of utilities. The attractiveness of this scheme depends on the distance and the transportation involved and the method of financing. It would probably have to be a facility financed by the electric power industry and operated by the chemical industry under a contractual arrangement. It is possible that the utility could pay enough for the return of the absorbing medium to make it attractive for the chemical company.

A central facility is attractive for several reasons:

1. The utilities evidently prefer not to get into the chemical business.

2. The recovery operation in many of these processes requires facilities and space comparable to the boiler plant.

3. The economy of scale for a central unit would be better than that of a single

utility plant, in which the installation of a chemical plant of uneconomic size would not be feasible.

4. The central processing facility could operate at a higher and more uniform rate than one located at, and dependent on, a single power station operating on a varying load factor.

It has been suggested that the ultimate control facility might be a combination major power plant, petrochemical, and sulfur-chemical complex. Coal chemicals are presently produced in quantity during coke manufacture by the steel industry. These organic chemicals are used as feed stocks for petrochemical processes in competition with petroleum refinery products. A similar activity may evolve from the utility companies as they strive to reduce pollutant emissions from coal and other fossil fuels used in power generation.

E. RESEARCH PLANNING

From a national point of view, the research strategy should be to have several processes in commercial operation at the earliest possible date. Primary emphasis should be placed on achieving industrial feasibility for the processes that can be readily incorporated into existing power plants, even though some of them may produce only nonsalable or throw-away byproducts. Successful development of these processes would do most to alleviate air pollution in the shortest possible time.

Besides development of throw-away processes, development of product-producing processes must be continued. For the new installation, improved processes, including steps to recover some value from the sulfur, will be necessary to keep costs for future control within reasonable limits. Installation of many of these processes in existing plants would require major changes. Consequently, they are unlikely to be found broadly applicable to plants now in existence. Compliance with the standards that may be promulgated

within the next year or two will be extremely difficult at best, and may be impossible, even with the development and installation of the throw-away processes that appear to be nearly ready for installation.

The limestone injection processes expected to be available in 1 to 3 years will probably not be adequate for the long-term requirements, and NAPCA should continue to support the development of sulfur-recovery processes.

Coal cleaning should be studied further, at least on a small scale, until its sulfur reduction potential is clearly defined. Imaginative new methods for removal of both pyritic and organic sulfur from coal should be encouraged.

The panel places special emphasis on the following:

1. Complete development of the limestone process should be given high priority because it seems applicable to existing boilers. At the same time, NAPCA should support long-range research on processes that industry will be slow to develop. Fluidized bed combustion, which has potentially attractive antipollution features, is such a process.

2. Coal cleaning processes should be refined to their maximum potential. Promising new concepts in coal desulfurization should be supported.

3. Processes for desulfurization of fuel oil are being developed by several petroleum companies. It is believed that NAPCA cannot, nor should it, contribute significantly to these developments.

4. Probably, much of the NO_x will have to be removed from stack gases or combustion temperatures controlled to reduce its

generation. Only two of the SO_2 processes under development appear to be potentially effective in removing oxides of nitrogen. *Research on ways to combine SO_2, NO_x and particulate abatement should be supported.*

5. NAPCA should employ a *process engineering and construction firm* to project costs on a *common basis* for all of the promising processes at various stages in their development. This not only would provide more reliable estimates of the ultimate cost of sulfur control, but also would provide NAPCA with a valuable guide in contract allocation and scale-up decisions.

6. Recovery of sulfur in the elemental form is desirable for storing and handling. Though acid-producing processes will find application in special marketing situations, acid sales will generally be limited by shipping costs.

7. Most of the processes using regenerable absorbents or adsorbents produce SO_2. The conversion of SO_2 to elemental sulfur is not a common industrial process, and it is important that the technology of this conversion be thoroughly studied.

8. The following general considerations should be kept in mind in choosing processes for development:

   a. Insertion of equipment ahead of the air preheater is a radical change in power plant design that may find slow acceptance in the power industry.

   b. Parallel absorber-regenerators, which require shifting the gas flow from one vessel to another, will necessitate large investments in

dampers or other flow control apparatus.

c. Solid absorbents are subject to attrition and to chemical deterioration.

d. Finely divided solid adsorbents are difficult to recover completely from the gas stream.

e. Processes that involve flow of the stack gas through all the equipment, both for absorption and regeneration (or other type of product recovery), have relatively high capital cost.

f. High absorbent loading and good mass transfer and sorption kinetics are important in keeping equipment size at a minimum.

g. Gas reheating, while expensive, may be needed to take care of the loss of buoyancy of stack gas in some treatment processes.

h. Impurities will accumulate and cause trouble in absorbent-recycle processes.

i. The disposition of sulfate formed is a major problem in any absorption process.

j. Processes that lead to fertilizer products may be desirable under some circumstances, because much of the recovered sulfur can be used by the fertilizer industry.

F. PROCESS DEVELOPMENT

1. General Considerations of Individual Processes

Brief commentaries on each class of the processes reviewed by the panel are presented here with special emphasis on the general process considerations. In each of the descriptions, the current level of knowledge about the process is reflected in the state of process development (bench, pilot, or demonstration level).

Generally speaking, bench-scale work may proceed for several years, depending upon what is already known about each of the individual steps of the process. Pilot-plant design and construction may take from a few months to more than a year following completion of bench-level work. Normally, the pilot plant would be operated for about 1 year. Scale-up, together with design and construction of a demonstration plant, following successful pilot-plant studies, takes from 1 to 2 years. Demonstration work will take 1 to 3 years to provide adequate information about the process. Thus, a process for which bench-scale studies have been completed is generally at least 4 1/2 years away from industrial feasibility, assuming success in subsequent studies. The schematic in Figure 3 summarizes the time scale for process development.

The panel was impressed by the readiness with which full information concerning the several proprietary processes was disclosed and has no reason to suspect that there is a major domestic effort on SO_2 control that has not been reported because of proprietary reasons.

A wide variety of processes are being considered in the United States (Appendix C) and in foreign countries (Appendix D). A number of these are reviewed here--particularly those that are receiving the most attention in the United States. In most cases, the developers are seeking funds from industry or Federal agencies, or some combination of the two to supplement corporate funds in expediting

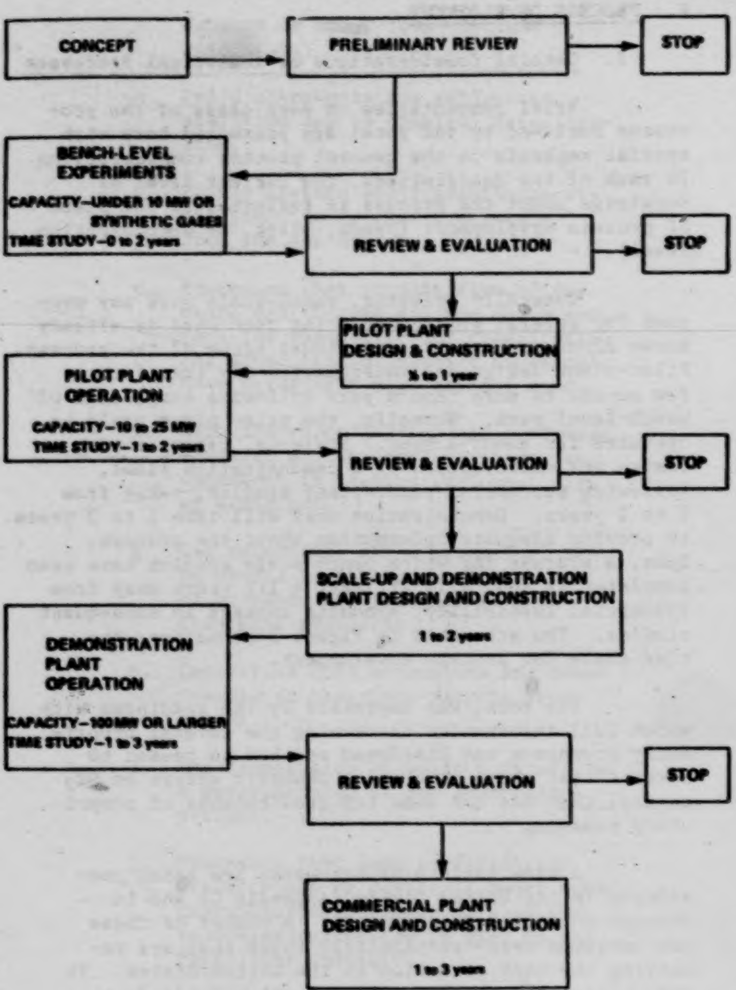

Figure 3. Time scale for process development.

the next level of feasibility investigation and reducing the time required for full-scale demonstration.

2. Precombustion Processes

Coal cleaning and coal gasification are processes that attempt to overcome the sulfur oxide emission problem prior to combustion. The processes have the potential advantage of removing the sulfur at higher concentrations than are present in the stack gas. They also provide for the recovery of sulfur or pyrite and would contribute to the conservation of this resource.

a. Coal Cleaning

Coal washing or beneficiation by present methods is limited to reduction of pyritic sulfur and can be expected to yield only a moderate increase in the supplies of low-sulfur coals. In some cases, sulfur emissions may be controlled by combining coal washing with sulfur removal from stack gases by the dry-limestone or other relatively inexpensive processes.

Coal beneficiation to reduce ash content has been a regular practice of the industry for years. Some pyrite is also removed, but only in the past few years has specific attention been directed toward sulfur removal by this procedure. The sulfur in many coals is present in about equal parts as pyrite and organic substances. Differences in the specific gravity of coal and pyrite are the basis for accomplishing sulfur removal; however, only part of the pyrite sulfur can be removed by gravity cleaning methods. The pyrite is present as nodules on cleat faces, and as disseminated small veins and crystals. In some coals, the larger pyrite particles may be partially freed by crushing and grinding the coal. Some types of coal are more easily cleaned than others, depending upon the manner and form in which the pyrite is present. Experiments with organic solvents, such as hexane, to remove the organic sulfur indicate that prohibitive costs would be involved.

The coal cleaning process produces a pyrite-rich reject as well as the cleaned coal. The reject stream may be further separated into a concentrated pyrite and a high-sulfur fuel. These may be used, respectively, for sulfuric acid manufacture and in a combustion unit with flue gas scrubbing or some other means of SO_2 control.

The Bureau of Mines and Bituminous Coal Research have had active programs in air cleaning and coal preparation for years. Pilot tests on air and water classification and other means of removing pyrite from coal have been made. Studies include the technology of pyrite separation, washability tests, evaluation of standard coal cleaning equipment, in addition to flue gas processing.

b. Coal Gasification

Present projections indicate that the cost of generating electricity from low-sulfur gas produced from coal will be greater than the cost of obtaining the same energy directly from coal. Coal gasification's potential will depend greatly on the availability of natural gas and on the cost of alternative methods for SO_2 control. Because gasification is potentially an alternative method of reducing SO_2 emissions to the atmosphere, the panel suggests that consideration be given to less sophisticated and possibly less costly gasification processes that would produce a relatively clean lower-heating-value gas, suitable for onsite use, but not of pipeline quality.

The Office of Coal Research has an active program for the development of pipeline gas and liquids from coal. While the manufacture of pipeline-quality gas from coal is not competitive at present, it appears that it may become so, as gas demand increases, natural gas reserves decline, and the technology of gasification processes improves in the next 5 to 10 years.

At present at least four processes are being considered:

1. Hydrogasification--Institute of Gas Technology

2. CO_2 Acceptor--Consolidation Coal Company

3. Two-Stage Super-Pressure Gasification--Bituminous Coal Research

4. Molten Salt Process--Kellogg Company

These processes require preliminary grinding, and those using lignite require drying. For coal hydrogasification, a mild air-oxidation pretreatment is used to avoid agglomeration in the hydrogasifier. The BCR process uses high pressure combustion to provide heat in the gasifier; the Kellogg process circulates hot molten salt to the gasifier; and the CO_2 Acceptor process employs the reaction of calcined dolomite with CO_2. Hydrogen is obtained by reacting char and steam. All processes require purification plus methanation to upgrade the gasifier effluent to gas of pipeline quality. During the purification step, sulfur is removed as an H_2S feed for a Claus plant.

The Institute of Gas Technology Hygas process is the nearest to commercialization and, assuming success in the pilot studies, will be commercially available in the late 1970's. IGT is starting up a 5-ton-per-day pilot plant, funded by the Department of the Interior Office of Coal Research, in Chicago for further study of the Hygas process. Only recently has attention been given by IGT to production of gas of less than pipeline quality for power plant fuel.

In addition to the research being supported by the Office of Coal Research, several companies are developing coal gasification processes of their own to produce either pipeline or sub-pipeline quality gas. It should be noted that low-heating value gasification processes will require sulfur removal from volumetric flows only slightly smaller than stack gas rates, thereby reducing the advantage of easier sulfur removal resulting from the higher concentrations.

3. Combustion Processes

The new combustion processes remove the sulfur during burning by methods that do not require extensive stack gas cleanup. Some of the more promising processes that offer the possibility of being brought to commercial acceptability in the later 1970's are discussed below. These processes also offer the possibility of sulfur recovery and the corresponding conservation of sulfur resources.

The combustion processes proposed for sulfur oxide control require new concepts of boiler design. The manufacturers and utilities have standardized boiler design to the extent that few major changes have been made in recent years. Additional effort will be required to obtain acceptance of these processes by industry since changes in manufacturing procedures and in operation will be necessary. The processes offer some of the more logical approaches to sulfur oxide emission control and deserve the extra level of support that will ensure their full consideration.

a. Fluidized Bed Combustion (FBC) is a new concept in boiler design and would be applicable only to new plants. The burning fuel is contacted with a fluidized bed of limestone particles which react with the sulfur. A portion of the bed is continuously removed and replaced with fresh limestone. Several FBC systems are being studied in England. The (British) National Coal Board is conducting research on atmospheric and pressurized systems. Esso Research Ltd. has been developing a two-stage FBC unit in which high-sulfur residual fuel oil is burned and sulfur values recovered. In the United States, the firm of Pope, Evans, and Robbins (under sponsorship of the Office of Coal Research and the National Air Pollution Control Administration) has conducted pilot plant work and studied the applicability of fluid bed combustion to industrial boiler systems. The National Coal Board projects that scale-up, from current laboratory testing, to a 20- to 30-MW single-stage atmospheric pilot unit can be completed by 1972.

b. <u>The Black, Sivalis, and Bryson Combustion Process</u> is a new concept in boiler design, in which sulfur oxide formation is prevented by the submerged partial combustion of coal in a bath of molten iron. The resulting carbon monoxide is burned above the molten bath. The sulfur is removed with the ash-slag and is subsequently recovered as sulfur. Black, Sivalls, and Bryson are conducting feasibility studies and have begun pilot plant design.

4. <u>Limestone Processes</u>

The limestone processes for sulfur oxide removal should be given priority in terms of research money and encouragement, because sufficient work has been done on these processes to suggest that they may become commercially acceptable sooner than any of the processes that produce salable products. Moreover, it appears that, for some applications, the net cost of throw-away processes may be less than for a recovery process. This is particularly true of a station that has been in operation for some time, since amortization of the cost of the control equipment would be over the remaining life of the plant, and the load factor of the plant would be lower in its later years.

Problems may arise with limestone because of limitations on the space available for disposal of waste products. In some locations, this could be expensive and tip the balance toward a recovery process. On the other hand, the dry-limestone process can be used intermittently for incident control, and thereby reduce the amount of material handled. This could be done in certain areas of high pollution levels where local control at specific times is needed.

The possibility that the limestone-based processes may solve an air pollution problem but create a water pollution problem is one reason that the panel endorsed NAPCA's plan to install plant-scale test facilities at TVA, where full consideration will be given to various ways of handling air and water pollution and solid wastes. The government effort has merit because the plans are to study the situation not only for dry-limestone but also for scrubber design

alternatives; this would expand the applicability of the limestone processes. In addition, the technology developed for SO_2 removal by limestone-wet scrubbing will contribute to the general knowledge of wet scrubbers, and this will be useful in other wet scrubbing processes.

The panel does not favor the dry- or wet-limestone processes exclusively, but merely as a stopgap or a first line of defense. There are other processes that will have to be developed to provide more adequate control of emissions. Limestone injection technology seems nearest to industrial application and therefore deserves priority in the near term.

The limestone processes appear to be applicable to many existing power plants. Because they do not produce a salable product, the limestone processes should appeal to utilities not wishing to get into the chemical business. The lower capital costs make these processes attractive to the older plants operating with low-load factors. There is added cost for the additional fly ash removal, and there is a probable increase in particulate emissions resulting from the increased precipitator load for the dry removal process.

While the limestone processes are generally thought of as not producing a salable product, there is the possibility of recovering sulfur dioxide by heating the calcium sulfite portion of the recovered solids. With control of oxidation to sulfate, this could provide for recovery of most of the sulfur dioxide and reuse of the limestone. This area will also be covered in the TVA study.

a. Limestone-Wet Scrubbing was originally studied at Battersea in London, England, and at the Tir John Power Plant in Swansea, Wales, during the 1930's. In this early work 90 percent removal of SO_2 was obtained [26] confirming the technical capability of the process. However, the work also identified specific problems of low reliability, high maintenance and operating costs, corrosion, abrasion, scale deposit, solid waste disposal and loss of plume buoyancy.

Current studies in the United States and other countries are attempting to overcome these problems through improved process and equipment design, closer control of operating parameters, improved materials, systems optimization, and reliability.

Limestone-wet scrubbing may be added to existing plants without significant boiler modification. Limestone may be injected into the boiler as well as added to the scrubbing liquor. Solids disposal will be several times the normal fly ash disposal rate. The Combustion Engineering Company has recently built two full-scale units at the Meramec Plant of the Union Electric Company in St. Louis and at the Lawrence Plant of the Kansas Power and Light Company. Each unit is designed to handle all the flue gas from a 125-MW boiler. Both plants have had start-up troubles but are expected eventually to meet the design objectives of 83 percent sulfur removal and 98 percent particulate removal. However, Kansas Power and Light Company is proceeding with plans for a 430-MW power plant, using the limestone-wet scrubbing process. Problems of scrubber optimization and waste disposal may require several years of additional study and are further discussed at the end of this chapter.

b. Limestone-Dry Removal uses an electrostatic precipitator. The process may be added to existing plants. Reaction time and temperature requirements are such that the process may not be applicable to cyclone-fired boilers. Solids disposal problems will be several times the normal fly ash disposal rate. The Tennessee Valley Authority is installing a 175-MW demonstration unit at its Shawnee plant near Paducah, Kentucky.

5. Processes for Sulfur Recovery from Stack Gases

Several processes for recovering sulfur from the stack gas following combustion are at or near the demonstration level. These processes will recover the sulfur oxide and convert it into products for the chemical industry, such as sulfuric acid, hydrogen sulfide, sulfur oxides, and elemental sulfur.

Domestic reserves of sulfur are limited, and consideration should be given to their conservation. It would be desirable to *conduct a study of the long-range supply and demand situation with regard to the several alternative by-products to aid in establishing priorities for support of control and abatement technology.* Most of the processes reviewed rely on relatively straightforward chemical reactions and processing equipment. The major technical problems are related to the low concentration of SO_2 in large volumes of flue gas containing a variety of corrosive materials.

a. The Cat-Ox Process of Monsanto Company is a direct translation of the contact sulfuric acid process. Boiler modifications are needed as the converter uses gas at temperatures of 700° F to 900° F. The process has been successfully piloted (15-MW equivalent) at the Portland, Pennsylvania, station of Metropolitan Edison Company. Monsanto has proposed the pilot unit as a modular alternative to commercial-scale demonstration. It is especially applicable to high-sulfur fuels, such as coal-cleaning middlings and ore smelting. This process could be commercially demonstrated by 1973.

b. The Wellman-Lord Process is an add-on process and does not require boiler modifications. Sulfur dioxide is recovered from the stack gas by scrubbing and reprocessing the scrubbing solution. During 1969, a 25-MW pilot study was conducted at the Crane Station of the Baltimore Gas and Electric Company. W. R. Grace Company, the Bechtel Corporation, Potomac Electric Power Company, Delmarva Power and Light Company, and Potomac Edison Company also participated in this study. A commercial Wellman-Lord recovery plant is being installed to recover SO_2 from the stack gas of a contact sulfuric acid plant of the Olin Mathieson Chemical Corporation at Paulsboro, New Jersey.

c. The Esso-Babcock and Wilcox Dry Adsorbent Process requires boiler modification to provide 900° F gas. Regeneration of the adsorbent produces sulfur

dioxide for a sulfuric acid plant. A 2,000 CFM bench-scale unit is in operation, and a 25-MW pilot plant is planned. If this is successful, a demonstration unit costing approximately $7.5 million is planned, with the objective of developing a commercial process by 1973. Sixteen utilities in the midwest and eastern United States and Canada are cooperatively funding the project.

d. Magnesium Oxide Scrubbing is an add-on process in which the scrubber removes both sulfur oxides and particulates. Chemico proposes a central recovery plant to remove sulfur dioxide and recycle the magnesium oxide to the power plants. Chemico and Basic Chemicals are conducting pilot studies of the process.

e. The Formate Scrubbing Process is an add-on process in which the reprocessing of the scrubbing solution yields a feed gas for a Claus plant for sulfur recovery. Bench-scale studies have been conducted by Consolidation Coal Company.

f. Ammonia Scrubbing of stack gases can be done as an add-on process without boiler changes. Sulfur dioxide can be stripped from the scrubbing liquid, using heat, or the solution can be acidified with nitric, sulfuric, and phosphoric acids to produce various fertilizers. Bench-scale studies were made some years ago. The renewed interest in the process lies mainly in the decrease in the price of ammonia in recent years.

g. The Westvaco Char Process is an add-on process. A source of hydrogen is needed for regeneration of the adsorbent/catalyst char and to produce a feed stream for a Claus sulfur recovery plant. Pilot-level studies are being conducted by Westvaco.

h. The Molten Carbonate Process is intended mainly for new plants with modified boilers to provide the gas at 900° F. Reprocessing of the scrubbing melt produces a feed gas for a Claus sulfur recovery plant. Bench-scale studies have been made by Atomics International.

i. Sodium Bicarbonate Adsorption is an add-on process that removes both sulfur oxide and fly ash. Pilot-level studies have been conducted by Dow Chemical Company.

j. The Modified Claus Process is an add-on process and is an extension of the conventional Claus sulfur process. A source of hydrogen (natural gas) is needed for the process to recover sulfur. Princeton Chemical Research has conducted bench-scale studies of the process.

k. The Catalytic Chamber Process is a modification of the old lead chamber process and removes both sulfur and nitrogen oxides and produces sulfuric acid. It is an add-on process that requires some additional space. Bench-scale studies have been conducted by Tyco Laboratories.

l. The Ionics/Stone & Webster Process uses a scrubber and an electrolytic cell system to recover sulfur dioxide for subsequent sulfuric acid production. It is an add-on process that requires a significant amount of power. Pilot-level studies have been conducted by Ionics and Stone & Webster.

m. The Alkalized Alumina Process has received significant attention. Attrition of the alkalized alumina has been a continuing problem. Recent detailed engineering and cost analysis (by M. W. Kellogg) suggests that further work on this process is unjustified.

6. Scrubber Development

There is a wide variety of SO_2 removal processes that use scrubbers as the principal chemical contactor. Some, such as the lime scrubbing process, employ reactants that may cause scaling and plugging of equipment because of the precipitation of solids, while others, such as sodium salt scrubbers, use clear liquids containing no solids. Nearly all scrubber applications require corroision studies and materials evaluation. The problem is not simply a matter of

finding a single best scrubber for all applications, but to develop a scrubber technology for a variety of applications. Consequently, NAPCA plans to look at several scrubber types on a small scale in an effort to characterize process chemistry combinations and generate the background data necessary to select the best scrubber for the specific process. In this way scale-up would not be repeated for every promising process.

The proposal for work to be done by the TVA on the wet-limestone process involves a large development and testing effort on scrubbers. This same installation could conceivably be utilized with some modification to test other wet scrubber sulfur recovery processes, when technology reaches the stage at which testing on this scale is justified.

APPENDIX A

LIST OF PRESENTERS

The following organizations made presentations to the Panel on Control of SO_2 from Stationary Combustion Sources:

Babcock & Wilcox
Bituminous Coal Research, Inc.
Black, Sivalls, & Bryson, Inc.
Chemical Construction Corporation
Combustion Engineering, Inc.
Continental Oil Company
  (Consolidation Coal Company, Inc.)
The Dow Chemical Company
ESSO Research and Engineering Company
Institute of Gas Technology
Ionics Incorporated/Stone & Webster
The M. W. Kellogg Company
McNally Pittsburg Manufacturing Corporation
Monsanto Company
National Air Pollution Control Administration
North American Rockwell Corporation
  (Atomics International Division)
Office of Coal Research
Pope, Evans and Robbins
Princeton Chemical Research Company
Roberts & Schaefer Company
Tennessee Valley Authority
Tyco Laboratories, Inc.
Wellman-Lord, Inc.
WESTVACO

APPENDIX B

LIST OF CORRESPONDENTS

The following companies sent in material to the panel describing their activities and experience on control of SO_2 from stationary combustion sources:

Abcor, Inc.
The Air Preheater Company, Inc.
Air Products and Chemicals, Inc.
American Petroleum Institute
Basic Chemicals
The Carborundum Company
The Detroit Edison Company
Edison Electric Institute
Institute of Gas Technology
Joy Manufacturing Company
(Western Precipitation Division)
Kaiser Aluminum & Chemical Corporation
(Kaiser Chemicals Division)
The Kansas Power and Light Company
Nalco Chemical Company
Pennsylvania Electric Company
Precipitair Pollution Control, Inc.
Research-Cottrell, Inc.
Reynolds Metals Company
Reynolds, Smith and Hills
Slick Industrial Company
(Pulverizing Machinery Division)
Union Electric Company
United International Research, Inc.
Universal Oil Products Company
(Air Correction Division)
The Wheelabrator Corporation

APPENDIX C

UNITED STATES SO_2 POLLUTION CONTROL RESEARCH AND DEVELOPMENT*

Company	Type of Work
Abcor, Inc.	Aqueous absorption systems for SO_2
Air Products and Chemicals, Inc.	Dry process for SO_2 removal
American Iron and Steel Institute	Studies of sulfur pollution control from various iron and steel manufacturing steps
Argonne National Laboratory	Reduction of atmospheric pollution by the application of fluidized bed combustion
Babcock & Wilcox	Magnesium oxide scrubbing system and other SO_2 removal processes
Basic Chemicals	Magnesium slurry scrubbing (in conjunction with Chemico)
Bituminous Coal Research, Inc.	Use of limestone or dolomite for SO_2 removal from coal-burning boiler flue gases
Bituminous Coal Research, Inc.	Removal of pyritic sulfur from coal
Black, Sivalls, & Bryson, Inc.	Coal gasification in molten iron; sulfur removal in slag
The Carborundum Company	Limestone injection with wet scrubbing or bag filtration
Chemical Construction Corporation	Various projects for SO_2 control from sulfuric acid plants and power plants
Combustion Engineering, Inc.	Limestone injection-wet scrubbing process

*Compiled by NAPCA, March 1970.

Company	Type of Work
(Kansas Power and Light Company)	Demonstration of Combustion Engineering limestone injection-scrubbing process
(Union Electric Company)	Demonstration of Combustion Engineering limestone injection-scrubbing process
Consolidation Coal Company, Inc.	Flue gas scrubbing, fluidized combustion in a lime bed, and pyrite removal from coal
The Detroit Edison Company	Limestone scrubbing, ammonia injection
The Dow Chemical Company	Gas-phase removal of SO_2 with solid alkaline materials
Edison Electric Institute	Dispersion characteristics of stack effluents, development of a formula for stack design
ESSO Research and Engineering Company	B&W-Esso proprietary process for SO_2 removal
General American Transportation Corporation	Catalytic reduction of SO_2 to sulfur
Hydrocarbon Research, Incorporated	Catalytic hydrogenation of fossil fuels
Illinois Institute of Technology Research Institute	Oxidation and reduction catalysts
Institute of Gas Technology	Coal Gasification
Ionics Incorporated/ Stone & Webster	Regenerable aqueous scrubbing system for SO_2 removal and recovery (Stone & Webster-Ionics process)
Kaiser Chemicals	Improved dry sorbent for SO_2 removal
The M. W. Kellogg Company	Undisclosed process for power plant SO_2 removal
Monsanto Company	Catalytic oxidation of SO_2 with recovery of sulfuric acid
(Pennsylvania Electric Company) (Air Preheater Company) (Research-Cottrell)	Development of Monsanto catalytic oxidation process

Company	Type of Work
Nalco Chemical Company	Dry sorbent for SO_2
Petroleum Industry (Source: API)	Industry-wide R&D for sulfur oxides control
Pope, Evans & Robbins	Control of gaseous emissions from coal-fired fluidized-bed boilers
Precipitair Pollution Control, Inc.	Gas-phase removal of SO_2 with solid alkaline materials, and collection with fabric filters (cooperative work with Southern California Edison)
Pulp and Paper Industry (Source: NCASI)	Sulfur oxides control from sulfite and kraft pulping processes
Research-Cottrell, Inc.	Scrubbing equipment development
Reynolds Metals Company	Dry sorbents for SO_2 removal
Reynolds, Smith, and Hills	Scrubbing process for flue gas SO_2 removal
Slick Industrial Company	Dry SO_2 sorbent development
Southern California Edison Company	Gas-phase removal of SO_2 with solid alkaline materials, and collection with fabric filters
Stone & Webster	Regenerable aqueous scrubbing system for SO_2 removal and recovery (S&W-Ionics process)
United International Research, Incorporated	Regenerable scrubbing process removal; SO_2 converted to H_2SO_4
U.S. Bureau of Mines-Morgantown	Study of corrosion/erosion and of coal type during fluidized bed combustion
U.S. Stoneware Company	Process for SO_2 control from sulfuric acid plants
Universal Oil Products	Dolomite slurry scrubbing; catalytic hydrogenation of fuels

Company	Type of Work
Wellman-Lord, Incorporated	R&D of regenerable wet scrubbing process at Lakeland, Florida, and Tampa Electric, plus direct reduction of SO_2 to sulfur
Tampa Electric Company	Pilot study of Wellman-Lord process, contributed to Stone & Webster
(Bechtel Corporation)	Demonstration plant of Wellman-Lord process at Baltimore Gas and Electric power station
(Baltimore Gas and Electric Company) (Potomac Electric Power Company) (Delmarva Power and Light Company) (Potomac Edison Company)	Demonstration plant of Wellman-Lord process at BG&E power station in Baltimore
Western Precipitation Group (Joy Manufacturing Company)	Scrubbing equipment development
Westinghouse R&D Center	Evaluation of the fluidized bed combustion process
Westvaco	Adsorption of SO_2 by activated carbon
The Wheelabrator Company	Scrubbing equipment development
Wisconsin Electric Power	Lime scrubbing, other aqueous scrubbing systems

APPENDIX D

FOREIGN SO_2 POLLUTION CONTROL RESEARCH AND DEVELOPMENT*

Company	Type of Work
Australia	
Commonwealth Science Industrial Research Organization	Fluidized bed combustion
Czechoslovakia	
Research Institute of Inorganic Chemistry	Ammonia scrubbing of SO_2 effluent
Czech acid plant scrubbing	Ammonia scrubbing on H_2SO_4 plant tail gas
Fuel Research Institute	Fluidized bed combustion
Institute of Mines	Desulfurization of coal
England	
Esso Research Center	Fluidized bed combustion of oil
National Coal Board Coal Research Establishment	Fluidized bed combustion of coal
BCURA Industrial Labs	
LHF Patented Process Esso Research	Desulfurization of coal
Bankside and Battersea Process	Alkaline water scrubbing on Thames River
France	
Societe Nationale Des Petroles	Catalytic oxidation of flue gas
D'Aquatane (joint project with Halder Topsoe of Denmark)	
Ugine Kuhlmann-Weirtam Process	Ammonia scrubbing of flue gas
Societe Anonyme Activit	Fluidized bed combustion
Neyric	Desulfurization of coal

*Compiled by NAPCA, March 1970.

Company	Type of Work
Germany	
Bayer Double Contact Process	Two-stage catalytic oxidation of H_2SO_4 tail gas
Bischoff Process	Lime/Limestone scrubbing of flue gas
Lurgi Sulfacid Process	Wet char sorption of SO_2 from effluent
Activated Carbon Adsorption Bergbau-Forschung	Wet char sorption of SO_2 from effluent
Activated Char Sorption Bergbau-Forschung	Dry char sorption of SO_2 from gaseous effluent
Grillo Process	Sorption by proprietary mixture of metal oxides
Siemens-Schuchert Process	Sorption on iron oxides in silica gels
Holland	
Shell CuO process	Sorption on proprietary mixture of copper based metal oxides
NVCP (Nederlandsch Verkoopkantoor voor Chemische Producten N.V.)	Hydro desulfurization of oil
Italy	
University of Cagliari	Desulfurization of coal
Japan	
Kiyoura Ammonium Sulfate Process	Catalytic oxidation of flue gas
Nippon Kokan Ltd.	Lime/Limestone scrubbing of flue gas
Japan Engineering and Construction Co. (JECCO)	Lime/Limestone scrubbing of flue gas
Showa-Denko Process	Ammonia scrubbing
Hitachi Activated Carbon Process	Wet char sorption of SO_2 from effluent
Central Research Institute of the Electric Power Industry	Dry limestone injection for SO_2 control of flue gas
Resources Research Institute	Dry limestone injection for SO_2 control of flue gas
Mitsubishi DAP-Manganese Process	Manganese oxide sorption
Kanagawa	Aqueous scrubbing

Company	Type of Work
Poland	
Dry Ammonia Injection	Injection of gaseous ammonia into flue gas
Sweden	
BAHCO Lime-scrubbing Process	Lime/Limestone scrubbing of flue gas
U.S.S.R.	
Wet Limestone scrubbing at Kusnetsk Abagur Plant	Lime/Limestone scrubbing
Ammonia and sodium carbonate scrubbing-Voskresenskij Chemical Industry	Ammonia scrubbing
I.M. Gubkin Institute of Petroleum and Others	Fluidized bed combustion
Academy of Science	Desulfurization of coal
Lensovet Technological Institute	Desulfurization of oil
Yugoslavia	
Institute of Mines	Desulfurization of coal

APPENDIX E

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